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THE OCS PETROLEUM PIE

by

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ADMINISTRATIVE STATEMENT

This report analyzes a range of alternatives for managing Outer Continental Shelf Petroleum from the point of view of national income, public income, and developer income. The economic value of the resource is reviewed, and estimates of unit resource costs obtained for a range of find sizes, water depths and design wave heights. The basic result is that the economic rent associated with yet-to-be-discovered OCS petroleum could easily be in the hundreds of billions of dollars. Management alternatives examined include work obligation permitting, bonus bidding, royalty bidding, profits bidding, and public exploratory drilling followed by bonus bidding. Special emphasis is given the latter option and the ramifications and problems of this system examined in some detail. The report argues that either profits bidding or public exploratory drilling followed by bonus bidding are to be preferred to other alternatives from the point of view of national income and public income.

This publication is the final report for a Sea Grant research project to analyze the offshore mineral leasing and policies of the United States. This work, providing valuable insights and evaluations for several leasing/royalty alternatives, was supported in part by Grant No. NG-43-72, from the NOAA Office of Sea Grant, U.S. Department of Commerce, and in part by the Massachusetts Institute of Technology.

Ira Dyer
Director

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CHAPTER 1

THE OFFSHORE PETROLEUM MANAGEMENT QUESTION

1.1 Introduction

Alternate policies for managing Outer Continental Shelf petroleum leasing have been the subject of much discussion and considerable contention recently. Dissatisfaction with the present system has been expressed by interests ranging from environmental groups to the offshore petroleum industry itself. Suggested alternatives have ranged from nationalization of the industry to work obligation permit programs which in the extreme approach simple claim-staking. The purpose of this paper is to analyze some of these alternatives and discuss their likely consequences. The paper's view is unabashedly economic in nature, that is, we will concentrate almost entirely on the real income implications of the alternative policies.

This focus is consistent with the twin convictions that:

- Offshore oil is not basically an environmental issue;
- Offshore oil is not basically a shoreside job and development issue.

Rather, I believe that offshore oil is primarily a question of the amount of national income involved in the difference to this country of the cost of offshore oil and the cost of imported crude and the distribution of this difference in national income between the developer and the public and between the adjoining coastal state and the rest of the nation.

Our work in the environmental issues associated with offshore oil at MIT over the last three years has convinced me that overall the environmental tradeoff between OCS production and its alternative is quite weak. Our statistical studies of past spill data (1, 2) have indicated that about the same amount of oil will be spilled in OCS production as in importing the crude. In some cases, OCS production has a slight advantage in the distance offshore that this oil will be spilled, although the difference is not overwhelming. From an environmental point of view, the major impact of OCS oil will be a different localization of some of the environmental costs associated with our consumption of petroleum than would exist without it. On a national scale it is basically a wash.

Our work on the economics of offshore oil (3, 4, 5) has convinced me that the <u>net</u> impact of the onshore development occasioned by OCS production is usually much overrated. The present value of the gross payrolls associated with on-site jobs and direct support facilities is a few score million for even a very large development (3). When one deducts the opportunity costs of these resources, the cost of public service, etc., the net impact even on a regional scale is much smaller and in some cases of high employment and rapid development can even be negative. Both Texas and Louisiana are now claiming the impact is negative (6). In contrast, the difference between the national cost of OCS oil and its alternatives for a large find can easily be several billion dollars, as we shall see. Whether the onshore job and taxes impact is positive, zero, or negative, it is very, very small compared with the potential economic rents.

Therefore, in this paper I intend to focus on the difference in the economic rent associated with OCS oil and the issues it raises both because of its overwhelming importance in terms of dollars compared to the above and because, despite this importance, it tends to be overlooked by policymakers in a debate that centers on environment versus shoreside payrolls and taxes.

If one is going to address real income, the first thing that one must specify is whose income one is analyzing. From the point of view of public policy with respect to OCS petroleum, there are several groups whose market wealth one might be interested in. The five groups which we will concentrate on in this paper are:

1. the nation as a whole

2. the developer
3. the public, i.e. the nation less the developer
4. the adjoining coastal state
5. the nation less the adjoining coastal state.

These, of course, are not the only five groups whose change in real income as a result of a particular leasing policy one might analyze. The possibilities are myriad, ranging from your Great-Aunt Bessie to New England farmers whose income is less than $6,000. In general, for each different definition of the group whose income is being analyzed, one will obtain a different answer. However, it is also obvious we can't analyze every subset of citizens of the United States. The five subsets listed above are perhaps the five most interesting choices of group. By analyzing the problem from the point of view of each of these groups, we will be able to speak to at least the major policy issues with respect to offshore petroleum management.

Before entering into this analysis, I am going to develop some background which may strike some as obvious. For this I make no apology. This study is aimed at intelligent laymen and, frankly, at legislative policymakers--people who are too smart to refrain from asking the obvious questions. The obvious questions, after all, invariably turn out to be the important questions.

1.2 The Meaning of Real Black-Box Income

If we are to perform an income analysis for a particular group, we must first define just what we mean by the real income of that particular subset of society. One way of developing our definition of this group's income is to imagine that we have drawn a black box about this group. Every member of society who is a member of the group whose income we wish to analyze is placed inside this black box. Any member of society who is not a member of this group is placed outside this black box. Thus, if we are interested in the income of a particular individual, we draw our black box around this single person. If we are interested in national income, we draw our black box around all Americans. If we are interested in the income of a particular state or town, we draw our black box around the residents of that state or town and exclude everyone else.

For any black box, we define the total value of all the goods, priced at current market prices, which the inhabitants of that black box can consume, to be the real income of that black box.

Perhaps the easiest way of getting at the implications of our definition of real black-box income is to imagine that the black box is owned and controlled by a single personage--Uncle Eph we might call him. Suppose the black box currently under analysis is a particular state. Uncle Eph is the not-particularly-benevolent despot who owns this state. Uncle Eph is interested in the total value, at present market prices, of all the goods he can consume with the output of the rather extensive resources he controls. Uncle Eph realizes that he can allocate his resources in an infinite variety of ways, some of which will allow him to consume a higher total value of goods than others. Uncle Eph, for reasons he chooses not to discuss, would like to make this market value of his consumption as large as possible.

His resources include not only the land and water, the buildings and roads, vehicles and vessels of his state, but also its present human inhabitants. We might regard this latter brand of resources as Uncle Eph's fingers, in that they both produce and consume. Uncle Eph has no particular feelings about his fingers. He isn't interested in whether one finger rather than another consumes a greater share of the total value of all the goods he consumes. He is only interested in the total. He considers himself better off if this total value is larger, worse off if it's smaller, regardless of the distribution of production and consumption among his fingers.

Notice that in attempting to maximize this quantity, Uncle Eph is ignoring the fact that any proposed change in the allocation of his resources will almost certainly make some of his fingers worse off and some better off. Uncle Eph simply doesn't care. He prefers the change if the total value of the consumption of all his fingers is higher after the change than before. He will eschew the change if the total value is less. Our concept of black-box income ignores the distributional effects of any proposed change within the black box.

This limitation has obvious political implications, for what may be a net increase to the black box as a whole can affect a particular set of losers quite adversely. For example, real black-box income will be increased by a change which increases the real income of 90% of the black box's citizens by 10% and decreases the real income of 1% of the population by 70%, virtually wiping out this latter group.

There is another thing to notice about Uncle Eph. His is a provincial and basically selfish character. He only cares about his own ability to consume. He is completely indifferent to any effect, up or down, his choices might have on the income of entities outside the black box--the rest of the country, for example. Any change in income to someone who is not a citizen of the black box currently under analysis, no matter how large, is given no weight at all by our concept of black-box income.

Paradoxically, the fact that our concept of black-box income ignores the distribution of income changes within the black box and ignores any income change outside the black box is precisely the characteristic which allows us to think quantitatively about the economic conflicts inherent in OCS policy-making. To do this we need only analyze the same policy alternative from the point of view of a number of different black boxes sequentially. Analyzing the same policy from the point of view of national income (the black box equals all Americans), then from the point of view of developer income (the black box is the owners of the corporation investing in OCS oil) and then from the point of view of the public (the black box is all Americans less these investors), will reveal both where the second and third group have a common interest through their joint memberships in the first group and where they are in direct conflict.

The relationships can be illustrated by the pie analogy. Regard national income as a pie. The size of the pie represents the amount of national income. This income is consumed either by developers or by the public (non-developers). In general, different OCS management alternatives will affect <u>both</u> the size of the overall pie (national income) and the relative share of this income going to the developers and non-developers. Figure 1.1 schematically compares two hypothetical alternatives. Alternative A generates a higher national income than B, but B results in the public obtaining a larger proportion of the smaller pie, so that non-developer income is actually higher under B than A. Obviously, both groups can theoretically agree to jointly attempt to make the pie as large as possible. After all, in theory a larger pie can

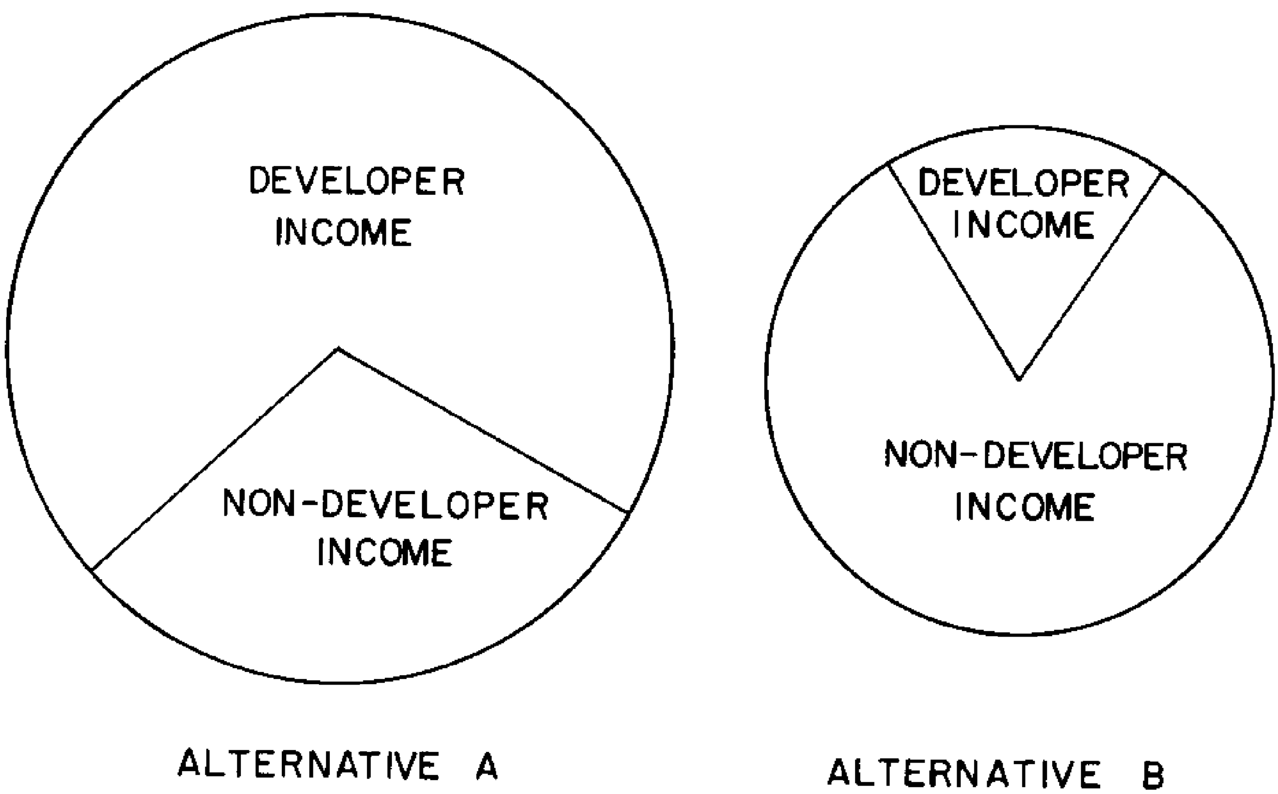


FIGURE 1.1 THE PIE ANALOGY

always be redivided in such a way that everybody gets a bigger piece than with a smaller pie. But the two groups are in direct conflict when it comes to dividing up any given pie.

The same reasoning, of course, holds for the adjoining state/non-adjoining states issue.

The only justification for this long-winded repitition of tautologies is that quite commonly these fundamentals are ignored in the public debate concerning the continental shelf. Antagonists broadcast all kinds of dollar figures without first specifying whose income they are discussing. The debate rages without any ground rules and as such cannot fail to be unproductive. One result is that in the confused squabble of each group for the largest possible share of the pie, we can easily end up with policies in which the overall pie to be divided up is substantially smaller than it need be.

1.3 Present Value

Whatever our black box is, it is obvious that changes in black box income can occur at different points in time. In order for the nation to produce offshore oil, it must invest resources now, labor, steel, fuel, etc., in order to obtain a time stream of petroleum which might commence three years in the future and extend over two decades. That is, we forgo the current income which could be produced by alternate employment of these resources in order to obtain petroleum production in the future. In so doing, it is imperative that we properly weight the true value of the resources, the capital, which must be diverted to produce this oil.

In order to see how we do this, let us take our black box for the moment to be the nation and look at the problem from the point of view of our folksy dictator, Uncle Eph. Uncle Eph is a shrewd old codger. He realizes that there is considerable difference between receiving one dollar in additional income now and one dollar in additional income ten full years from now. The reason, of course, is that Uncle Eph has the opportunity to invest the one dollar received now at some annual interest rate, say 10%. After one year so invested, Uncle Eph will have $1.10, which he can reinvest for a second year, obtaining an additional 10% on $1.10, or 11¢, for a total of $1.21, which he can reinvest, and so on. If he invests the dollar received now for ten years at 10%, he will find that at the end of the tenth year, his investment will be worth \$2.59, which is quite different from one dollar. The timing with which he receives the same amount of additional municipal income obviously makes a great deal of difference to Uncle Eph.

To put it another way, if Uncle Eph has investment opportunities which can earn him 10% per year, receiving one dollar now is equivalent to receiving \$2.59 ten years from now. He would be indifferent between receiving one dollar now and \$2.59 ten years from now, but he would certainly not be indifferent between receiving one dollar now and one dollar ten years from now.

Uncle Eph, therefore, realizes he has to put increases in black box income received at varying points in time on a common temporal basis. He chooses to relate them to an equivalent amount received now (1974). That is, in valuing an increase of one dollar which will occur ten years from now, he asks himself what is the amount received now which will grow to one dollar ten years from now. Mathematically he is asking:

What number x 2.59 = 1.00 ?

The number he is after is simply \$1.00/\$2.59 or 38.6¢. This number is called the <u>present value</u> of a sum \$1.00 received ten years from now assuming a 10% interest rate. In general, the present value of a sum x_n received n years from now at an interest rate i is

$$\frac{x_n}{(1 + i)^n}$$

If we are dealing with a development alternative which will increase national income by x_1 in year 1, x_2 in year 2, and so on through N years, then the present value of all these increases, V, is simply the sum of the present values of each yearly increase or

$$V = \frac{x_1}{(1 + i)} + \frac{x_2}{(1 + i)^2} + \frac{x_3}{(1 + i)^3} + \ldots \frac{x_n}{(1 + i)^N}$$

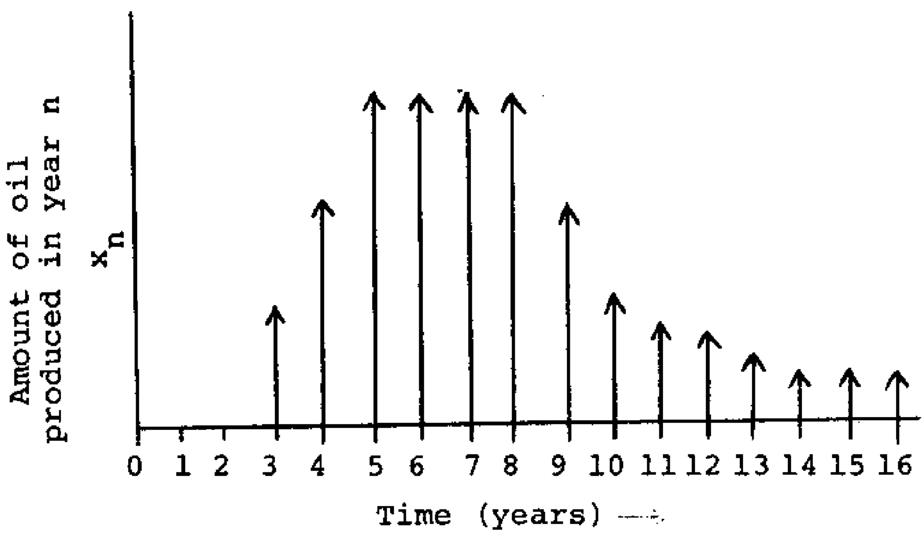
Uncle Eph reasons that, given his opportunity to reinvest at an interest rate i, he would be just as well off in terms of his real wealth if he received the sum V now as if he received the entire stream of future increases in income resulting from the development alternative. Thus, in comparing various development alternatives, he will do so on the basis of their present values, that is, on the basis of an equivalent amount of income received in 1974 on a one-shot basis.

The justification for applying Uncle Eph's reasoning to the nation follows from the fact that each individual citizen of the nation is either a borrower or a lender or both. Insofar as they are lenders, they are in exactly the same position as Uncle Eph and therefore future income must be adjusted downward relative to present income according to the interest rate at which he can lend. Insofar as a citizen who could be a lender does not do so, he is making a clear statement that he prefers one dollar's worth of consumption now to \$1.00(1 + i)'s worth of consumption a year from now. In both cases, future increases in income must be present valued at the interest rate available to these citizens. By the same token, insofar as a citizen is a borrower, he is making a clear statement that he is willing to exchange $(1.00 + i) a year from now for a dollar's worth of consumption now, where i is the interest rate at which he is borrowing.

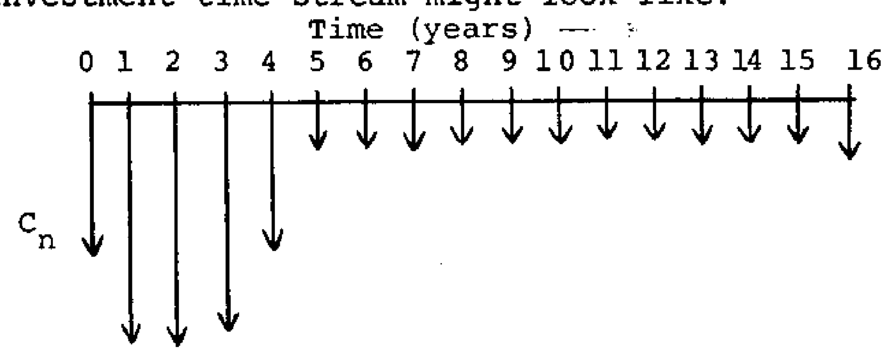
At this point, we had better say a word about inflation. All our analyses are based on 1974 prices. Thus, for example, if a particular worker's services are priced at $5.00 an hour in 1974, we will assume that his wage is $5.00 an hour in 1984. In reality, the general price level may have risen so that <u>in 1984 prices</u> the worker is earning, say, $6.00 an hour in 1984. However, we will implicitly deflate these prices back to 1974 dollars to put everything on the same basis. This holds for all future prices and costs. In particular, this procedure requires that we use inflation-free interest rates in obtaining present values. For instance, if an investor's best employment of capital is to buy a bond at a market interest rate of 13% for a given period during which price levels were rising at 3% per year, the investor will realize a 10% growth in his income in real purchasing power (in constant value dollars). Thus, in this paper, when we speak of an interest rate of 10%, we are talking about 10% net of inflation, which at present would correspond to a market interest rate of 15% or more.

1.4 The Unit Resource Cost of OCS Oil

Often it is convenient to place our present value calculations on a unit (per barrel) basis. Suppose that in order to produce and land the following time stream of oil from an offshore find



will require the nation to invest resources in each year whose cost in national income--the market value of what these resources could produce elsewhere--is C_n. That is, our investment time stream might look like:



The present value of these costs is

$$\sum \frac{C_n}{(1 + i)^n}$$

Since in this analysis our black box is the nation, we want to include in these costs only those financial transactions, those expenses, which represent actual diversion of resources to the offshore development. For example, the C_n would not include any payments to public bodies such as taxes, bonus bids, or royalties, which represent transfers of national income rather than diversion of resources. In order to put these costs on a unit basis we ask ourselves, what per-barrel price, c, would result in present valued revenues equal to these prerevalued costs, i.e.

$$\sum_{n=0}^{N} \frac{c}{(1 + i)^n} = \sum_{n=0}^{N} \frac{C_n}{(1 + i)^n}$$

where N is the life of the field. This is the break-even price on the development from the point of view of the nation; i.e. if oil can be landed from alternative sources, say, by importation at a cost of c, we will just break even in terms of national income by producing this offshore oil. If the cost to the nation of alternative sources is higher than c, then national income will be increased by the difference between this cost and c on a unit basis. If the cost to the nation of oil from alternative sources is less than c, then national income will be decreased by the difference. In this case, the resources required to produce the oil would be more profitably employed elsewhere.

We will call c the <u>unit resource cost</u> of OCS oil. Notice included in c is a normal return to capital. That is, if our development is privately financed, at price c the developers will be earning an interest i on their investment.

1.5 Economic Rent and Excess Profits

It has sometimes been alleged that in the absence of bonus bids, royalties, etc., the savings associated with domestic offshore oil would be passed on to the consumer in the form of lower prices. In this case, the increases in real national income would automatically accrue to the public. If this were the case, then one could make an argument for such simple OCS management policies as claim staking, both from the point of view of national income and public income.

However, in the absence of direct price regulation, this simply will not happen. Even assuming pure competition among the OCS leaseholders (homesteaders if you like), the landed price of OCS oil will not drop below the landed price of OPEC oil unless there is enough domestic production to push all foreign oil off the U.S. market--an extremely unlikely event.*

The reason is simple. Assuming competition, landed price of this oil will be determined by supply and demand. The supply curve of crude to the United States looks something like Figure 1.2. On the left-hand side of the curve is the domestic supply as a function of its unit resource cost to the nation. As we shall see, some of this oil can be quite cheap. The horizontal portion of the curve on the right represents imported crude. The reason why this portion of the curve is essentially horizontal is that the cartel of exporting countries,

*Or direct price control.

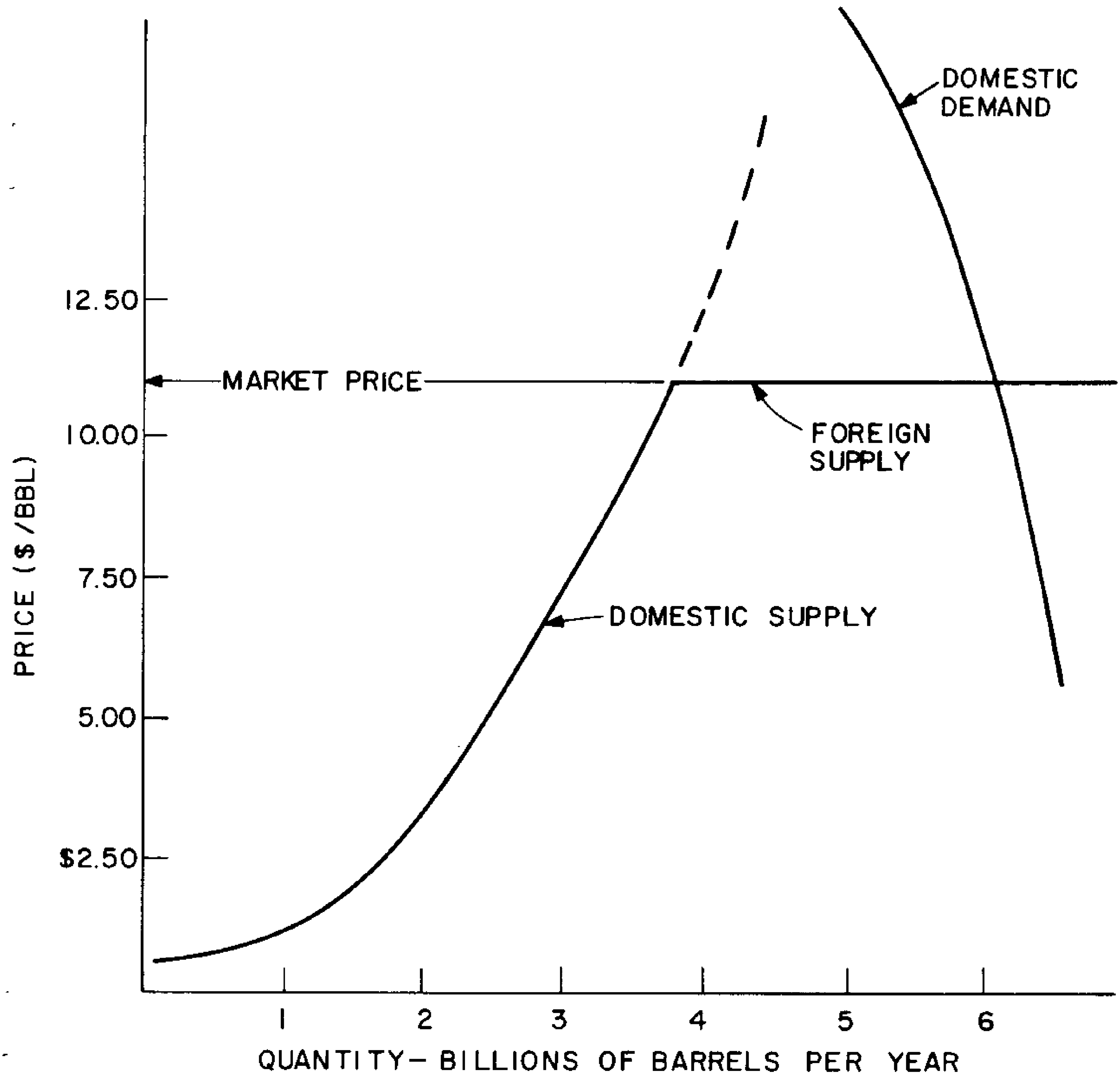


FIGURE 1.2 SKETCH OF U.S. OIL SUPPLY / DEMAND

under OPEC leadership, attempt to adjust their prices so that from the U.S. point of view it is as expensive to import from one source as from another. Essentially, once you meet the OPEC price you can buy as much oil at that price as you want.*

At present, the U.S. is importing some 2.25 billion barrels per year, about 38% of consumption. Unless domestic production increases to force all this oil off the market, demand curve will intersect the supply curve on the horizontal portion of the supply curve. The vertical level of intersection will determine the domestic price of crude. Regulation aside, no domestic producer will sell his oil for less than the landed price of foreign crude, for he knows that there are domestic buyers who are paying this price to whom he can sell his oil.

Given this situation, let's consider what will happen if we make a large find on the OCS. As we shall see, the landed resource cost of such oil can easily be less than $2.00. The effect of such a find on the supply curve of domestic oil is sketched in Figure 1.3.

As shown, the find is equivalent to a rightward shift of the supply curve at the unit resource cost of landing this find--$2.50 per barrel in the sketch. The

*This is not true during actual embargoes. From time to time the exporter cartel may call an embargo to raise the overall level of the horizontal portion of the curve. However, it is in the interest of the cartel to keep these embargoes relatively short; as soon as the price rise has been effected, the embargo is lifted and once again one can purchase as much as one wants at the new price.

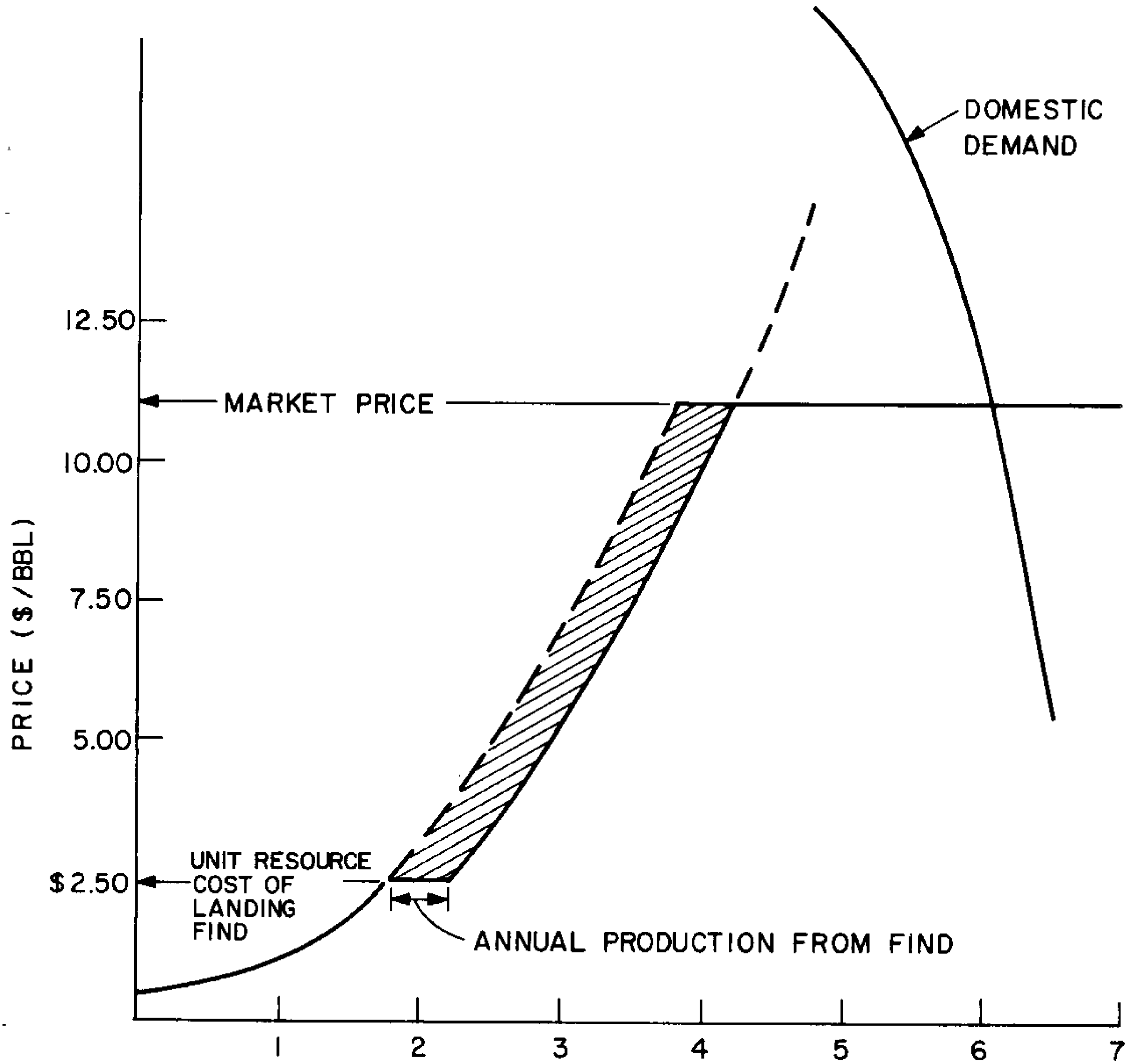


FIGURE 1.3 SKETCH OF U.S. OIL SUPPLY AND DEMAND WITH LARGE NEW FIND

amount of the shift is equal to the annual production from the find. Note that unless the amount of the shift is sufficient to push all foreign oil off the domestic market, there will be no change in price, for the intersection of the demand curve and supply curve is still at the same horizontal level. Under competition, market price will not be affected by any individual find unless the aggregate of such finds pushes all foreign oil off the U.S. market. To the extent that the relevant markets are not completely competitive, this statement holds a fortiori.

The fact that price is not affected does not mean that there has been no increase in national income. In fact, the annual increase in national income associated with the hypothetical find sketched in Figure 1.3 is the hatched area in the figure. This is the difference between the unit cost to the nation of imported crude and the unit resource cost of the OCS find multiplied by the amount of the find. In this case, we are replacing \$11.00 foreign crude with \$2.50 domestic crude for a net gain in national income of \$8.50 per barrel.

The hatched area, the gravy if you like, is known as the economic rent associated with the find. Where, then, will this increase in national income, this economic rent, show up? It will be split between the public and the investors in the development. The former will see lease payments, royalties and income taxes which would not occur if the resource were not developed. The latter will see profits in excess of what he would have achieved without the development. Notice that here we are using the word profits in a very restricted sense to imply profits above and beyond the normal return to capital which the investor could earn elsewhere, for this normal return to capital has been included in the unit resource cost by the present valuing process. To emphasize this usage we will use the term "excess profits" to describe these increases in developer income. Excess profits is not used in a pejorative sense. It is a technical term meaning profits greater than the normal return to capital.

The actual split between the public and the developer will, of course, depend on the OCS management policy being employed. On the one extreme, simple homesteading and no income taxes, the entire increase in national income, all the economic rent would go to the developer in the form of excess profits. On the other extreme are systems in which the developer is forced to bid away all the excess profits in the form of lease payments, royalties and taxes, in which case all the economic rent would accrue to the public. This split, the cutting of the pie, will be one of the central issues in our discussion of alternative leasing policies.

CHAPTER 2

THE IMPORTANCE OF OFFSHORE PETROLEUM TO NATIONAL INCOME

Nobody knows how much oil will be found in the United States in the future. Nonetheless, it is of interest to review the arguments which have been made relative to this random variable. In toto, we believe that they indicate that the importance of OCS petroleum to real national income is likely to be staggeringly large. Despite intensive industry attempts to convince the public of the criticality of offshore oil, the quantitative dimensions of this importance to national income have not really entered the public consciousness, perhaps because the industry advertising is designed in part to leave the impression that offshore oil is expensive.

The prospects for additional domestic supplies of petroleum divide themselves into two categories:

- New discoveries, onshore Lower 48
- New discoveries, onshore Alaska and OCS

2.1 Yet-To-Be-Discovered Oil, Onshore Lower 48

The specific question of how much oil remains to be found onshore in the Lower 48 is currently a matter of heated controversy. The U.S.G.S. has officially estimated undiscovered recoverable reserves at between 110 and 214 billion barrels (7). The National Petroleum Council's range is fifty-three to seventy billion barrels (8). A Mobil Oil Corporation study indicated eleven billion barrels. And a study done by M. K. Hubbert, a U.S.G.S. geologist, estimated nine billion barrels recoverable (10). In short, the present estimates vary by as much as a factor of twenty-five, which is hardly helpful.

These differences are in large part the result of differences in methodology. The U.S.G.S. figures were obtained by estimating, by region, the volume of prospective sediments, applying a productivity factor in barrels per cubic mile of sediments to this volume; this factor was based on productivity in the explored area within the region, or in geologically similar basins elsewhere, adjusted by the regional geolo gists' judgment. Hubbert's results, on the other hand, are based on a projection of the historical trends in discovery rates per foot of well drilled, which have fallen by an order of magnitude over the last fifty years, despite revolutionary advances in exploration technology in that period.

The U.S.G.S. methodology is inherently optimistic in that it ignores the fact that the best prospects are drilled first. Occasionally, the U.S.G.S. contributors would use a productivity factor for a large basinal area which was a fraction (typically 25%) of the productivity factor of the area which had been explored by drilling, but even this appears optimistic when one realizes that 71% of all the oil which has been found in the natural state has been discovered in structural traps and that very few large structures at oil-bearing depths (15,000 feet or less) have not been drilled. And often the U.S.G.S. regional editors were far from pessimistic, treating an area which had not been subject to intensive drilling as completely unexplored, despite the fact that the area had been initially explored by geophysical methods and considerable effort had gone into looking for conditions which would be favorable to stratigraphic traps.

The U.S.G.S. methodology also ignores the fact that most of the oil which has been found in the United States (and the world) has been found in a few, very large fields. Two hundred and fifty of the 50,000-odd reservoirs in the United States account for over 65% of domestic production to date, 75% of the API recoverable reservoirs, and over 60% of the already discovered remaining oil in place. And even within this sample of large fields, the distribution of volume is highly skewed toward the 100 largest fields. The eleven fields shown in Table 2.1 represent close to 50% of total domestic recoverable reserves according to Oil & Gas Journal. One field, Prudhoe Bay, represents about 25% of these reserves. The reason is simple. The range of domestic field sizes in terms of original oil in place runs from about 20 billion barrels to fields of a few hundred thousand barrels or less--over four orders of magnitude. In short, one very large find can be worth literally thousands of small finds.

TABLE 2.1

DOMESTIC SUPER-GIANTS
(Reserves in Millions of Barrels)

FIED	DISCOVERY DATE	O&GJ RESERVES
Prudhoe Bay	1968	9600*
East Texas	1930	1800
Yates	1926	1000
Elk Hills	1919	1000
Kern River	1899	850
Wilmington	1932	700
Wasson	1936	630
Kelly-Snyder	1948	500
Midway Sunset	1894	420
Hawkins	1940	300
West Ranch	1938	300
		∿17,000
Santa Ynez**		2000-3000

* Unofficial reports set recoverables at 12.5 billion.

** Not yet entered in reserves estimates.

Further, in general, large fields are easier to find than small ones. History bears this out. The average year of discovery of the sample of 200 largest domestic onshore fields is 1926 (10). In the last decade, there have been only four oil fields found onshore in the Lower 48 which have estimated original oil in place greater than 100 million barrels.*

Field	Discovery Date	Original Oil In Place (Billions of Barrels)
Jay	1970	.70
Big Wells	1969	.18
Bell Creek	1967	.62
Black Lake	1964	.10

In 1973, despite an all-time record in wildcat feet drilled and despite a near-record 701 wildcat successes (a sure sign of technological improvement), not one field rated at more than 25 million barrels of oil recoverable was found.

It is important to recognize that for a long time market prices have been such that the discovery of even a rather marginally sized field of, say, ten million barrels was an extremely profitable enterprise. And if one got lucky and discovered a Bell Creek, where the unit cost of production before royalties and taxes was less than 20¢ per barrel, then even at oil prices of two and three dollars a barrel one had a veritable bonanza (11). Given this situation, it was simply good sense to rather

*Future revisions and extensions may add one or two fields to this list.

intensively explore even rather low probability prospects. For example, there have been 506 exploratory wells drilled in South Dakota. All this effort has discovered two oil fields with a total of eighteen million barrels in place (12).

Kaufman (13) has developed an oil discovery model based on the premises that:

a. we are sampling without replacement from a finite population;

b. the probability that a given field in the population will be found next is proportional to the size of that field;

c. oil field sizes are distributed according to an exponential process.

One interesting and sobering result of this model is the mean size of the fields to be found decreases linearly with the number of fields already found. While Kaufman's model at this point is still just a theoretical construct, in our opinion its premises are much more defensible than those of the U.S.G.S., which is tacitly assuming that what we haven't drilled is similar to what we've already drilled.

Optimists with respect to the Lower 48 onshore normally base their optimism on either or both of two arguments:

1. stratigraphic traps
2. deeper drilling.

Present geophysical technology is not particularly adept at locating stratigraphic traps. Hence, the argument goes that if we obtain a breakthrough in technology, we might well find a lot of stratigraphic oil. That is, of course, a possibility. It requires two things: the advance in technology and the existence of a lot of oil in stratigraphic traps in the Lower 48 onshore which cannot be found by methods available in the past.

The technological advance may be at hand. The use of digital amplifiers is seismic signal processing has extended the range of the recording system to the point where it is possible to identify anomalous amplitudes at a given depth. Where before the geologist had to be content with the knowledge that a difference in density existed at a given depth, now he can sometimes obtain an estimate of the size of this difference. Since the difference in densities associated with petroleum, particularly gas, are typically larger than those associated with moving from one rock layer to another, anomalously large responses, known in the jargon as "bright spots", may be a direct indication of petroleum.

The efficacy of bright spot technology may be reflected in the high wildcat success ratio we are presently enjoying. However, it is basically a gas-oriented method which has yet to locate any sizable onshore oil fields. Another two or three years will tell us a lot about bright spot and the likelihood of a lot of oil in stratigraphic traps, at least those with gas caps.

Discoveries of deeper pays in already discovered fields onshore in the Lower 48 totaled 172 million barrels of oil recoverable in 1973, which is a welcome but not really significant addition to domestic supply. The big problem with going deeper on already discovered structures is that the increase in pressure and temperature imply that petroleum, if it is there, is more and more likely to be gas. Ninety-five percent of all the oil which has been discovered in the United States is produced from reservoirs of less than 11,000 feet depth. While oil can exist in certain situations at 20,000 feet, in general there is little prospect for oil much below 15,000 feet. Given the economics discussed earlier, if a major structure has not been drilled to 15,000 feet, there must have been good geographical or geophysical reasons for regarding the deeper areas as very low probability prospects. Some oil will certainly be found in deeper pays, but we cannot be optimistic about the amount.

In summary, we believe it would be prudent to assume that the additions to domestic supply from yet-to-be-discovered oil onshore in the Lower 48 will be quite marginal in terms of the twenties and hundreds of billions of barrels we will be discussing elsewhere in this report. Because of the size range of fields involved, a lot of small discoveries do not add up to a few big ones and, in our opinion, there is a good chance that very few really large fields will be found onshore in the Lower 48 in the future.

2.2 Yet-To-Be-Discovered Oil, Alaska and the Continental Shelf

The situation with respect to yet-to-be-discovered oil in Alaska and the Outer Continental Shelf is considerably different from that of the Lower 48 onshore. Unlike all the Lower 48 onshore, large portions of Alaska and the OCS can reasonably be regarded to be truly unexplored. Hence, the U.S.G.S. method of applying average productivity factors to estimates of the volume of sediments makes considerably more sense in these areas.

One result is that there are somewhat smaller discrepancies among the various published estimates of yet-to-be-discovered oil in the OCS and Alaska than there are for the Lower 48.

ESTIMATES OF RECOVERABLE RESERVES
(BILLIONS OF BARRELS)

	Offshore	Alaska-Onshore
U.S.G.S. (1972)	206	
NPC	192	
U.S.G.S. (1974)	65-130	25-50
Mobil	54	21
Nelson & Burke	15-35	
AAPG (Schmitt)	300	
Hubbert		28

However, the range is still extremely large. Once again we repeat that no one knows how much oil will be found in the future. But given the lack of exploration in these areas, we believe there is a good chance that the middle ranges, say, sixty to eighty billion barrels in primary yet-to-be-discovered oil will be achieved.

Several of the estimations break their OCS estimates down by major region.

	U.S.G.S. (1972)	U.S.G.S. (1974)	Mobil	AAPG
Atlantic	48	10-20	6	5.5
Gulf of Mexico	50	20-40	14	
Pacific	9	5-10	14	
Alaska	62	30-60	20	

The dominance of Alaska in these projections is a product of the size of the Alaskan shelf. The NPC rates 582,000 square miles of the Alaskan shelf as prospective as compared to 293,000 square miles of shelf area for the rest of the United States. The volume of sedimentary rock on the Alaskan continental shelf is estimated at 800,000 cubic miles; that for the rest of the OCS, at 862,000 miles. By comparison, the volume of sedimentary rock onshore in the Lower 48 is about three million cubic miles, and onshore Alaska is listed at 215,000 miles.

From the point of view of national income, gross oil to be discovered figures by themselves are almost meaningless. They must be combined with the resource cost to the nation of landing that oil. Obviously, even if we find 100 billion barrels of oil, if the cost to the nation of landing that oil, in terms of the things we could have had with the resources, the steel, the fuel, and the people and the brain power which must be used up in obtaining this oil, is the same as the value of the resources which must be devoted to producing the goods with which we pay foreigners for their crude, then the nation has gained nothing. The discovered domestic oil would not increase national income. It is, in a very precise sense, worthless. If the resource cost of this oil is greater than the cost to the nation of foreign crude, then it should not be landed and, in the absence of government subsidy, will not be landed. If, on the other hand, the resource cost of this domestic crude is less than the cost to the nation of foreign crude, currently about $11.00 landed, then the development of this oil will increase the size of the national income pie by the <u>difference</u> in the resource cost of landing the domestic discoveries and the cost of landing foreign crude. In short, the likely resource cost of the yet-to-be-discovered OCS oil is at least as important as the magnitude of that oil from a national income point of view.

In order to address the resource cost question, we have exercised the MIT Offshore Development Model over a range of hypothetical OCS discoveries. The Offshore Development Model is a computer program, developed and refined over the last two years, which attempts to simulate the primary response of a given offshore reservoir to a specified development strategy and, by iterating over such strategies, to delineate that strategy which the profit maximizing developer will undertake together with the resulting financial and petroleum flows. The general logic of this program is described below. A complete description of the model is given in reference (4).

The Offshore Development Model takes as input three sets of variables: geologic, locational, and financial/regulatory, as well as a number of program control variables and options. The geologic variables include such descriptors of the hypothetical find as oil in place, gas in place, type of drive, number of fields, field separation, depth, permeability, porosity, formation thickness, initial reservoir pressure and termperature, gas and oil viscosity and density, etc. A complete list of these input variables is given below.

RESERVOIR INPUT PARAMETERS

Oil in place	Residual oil saturation
Gas in place	Residual water saturation
Rock type	Oil API number
Formation pressure	Type of drive
Formation temperature	Gas viscosity
Formation thickness	Oil viscosity
Formation porosity	Kickout depth
Formation permeability	Depth to formation
Pressure depletion increment	Drilling maximum slantangle
Number of fields containing reserves	Connate water
	Oil compressability
Field separation	Formation compressability
	Water compressability

Locational parameters include water depth, relevant distances to shore, terminal draft limitations. A complete list of these input variables is given below.

TRANSPORTATION INPUT PARAMETERS

Tanker sea distance	Mobilization distance
Refinery port draft limit	Oil pipeline sea distance
Refinery port "lost" time	Oil pipeline land distance
Refinery port SBM distance to shore	Gas pipeline sea distance
Refinery port SBM distance from refinery to shore	Gas pipeline land distance
Design wave height	Refinery port terminal building option
Transport option indicator	Pipe yield stress
Bottom type	Maximum pipe wall thickness
	Weather down time

Financial regulatory variables include landed price of oil and gas through time, cost of capital, the lease payment, royalties, oil and gas allowables if any. These input variables are listed below.

FINANCIAL INPUT PARAMETERS

Investor's cost of capital	Yearly landed oil price
Borrowing interest rate	Yearly landed gas price
Debt/equity ratio	Initial production year (relative to 1972)
Fraction of pre-lease bid profits bid away	Oil allowable
Steel cost	Gas allowable
Maximum number of platforms which can be installed in a year	

General program control variables are primarily concerned with computational options within the computer program. They include the minimum and maximum number of platforms per field which the program user wants the program to consider, the minimum and maximum number of wells per platform to be considered, the maximum of pump/compressor platforms and an option which specifies whether oil and gas pipelines have the same destination. The user can also specify that certain of the transport options are not to be considered.

The general logic of the program is indicated by Figure 2.1. Basically, the program examines a number of combinations of production schedule and transport system and chooses that combination which maximizes the developer's present valued profits.

More precisely, the program takes as input one of the key developer decision variables, amount of gas reinjection. The program then examines a range of number of platforms deployed and a range of number of wells per platform. These three decision variables, together with the reservoir's physical characteristics, determine an oil and gas production schedule through time. This production by year is determined by a modified Muskat-Hoss gas drive reservoir model if gas solution drive is specified, and by an edge-drive infinite aquifer, Hurst-Van Everdingen/Tarner combination drive model if water drive is specified.

For each such production schedule, the program examines a range of both tanker and pipeline systems for transporting the oil and gas to shore.* Tankers of 20, 30, 40, 80, 150, and 250 thousand deadweight tons are considered, subject to terminal draft limitations. Pipelines ranging from 8 to 48 inches in diameter are examined in approximately 4-inch increments combined with 1 to 5 pump/compressor platforms and 1 to 4 parallel lines which

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*The model operates under the assumption that gas can be transported to shore only by gas pipeline. Two-phase flow is not considered.

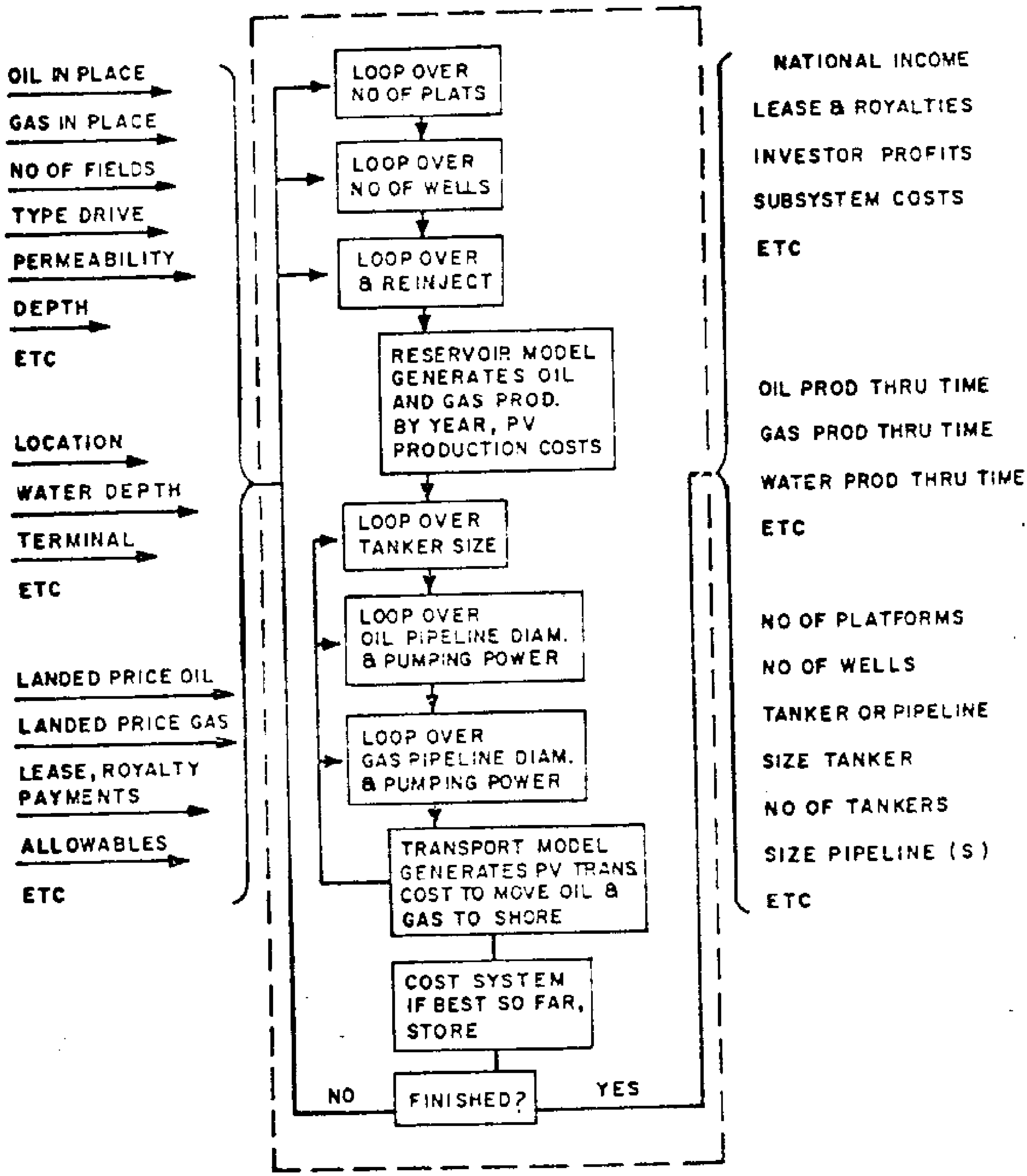

FIGURE 2.1 OFFSHORE DEVELOPMENT PROGRAM.

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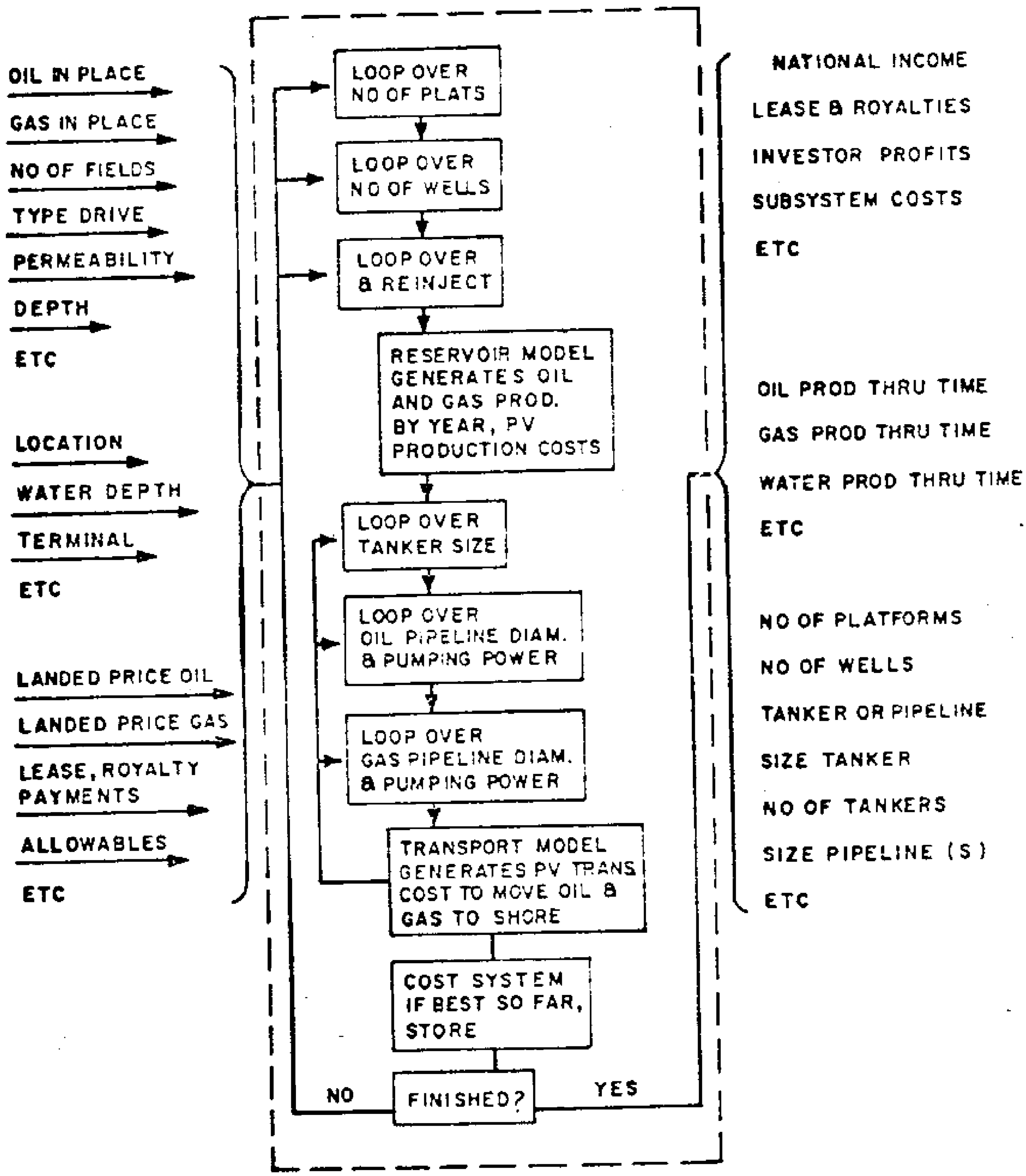

FIGURE 2.1 OFFSHORE DEVELOPMENT PROGRAM.

may come on line at different times. That combination of tanker and gas pipeline, oil pipeline and gas pipeline, oil tanker only, or oil pipeline only which maximizes present valued gross revenue less transport costs is selected as the transport system for the particular production schedule under consideration.

This transport system and its cash flow are combined with the field capital and operating costs to generate all the cash flows associated with the combination of production schedule and transport system currently under analysis. The after-tax present valued profits are computed assuming a bonus bid equal to some fraction (user-specified, up to 99%) of his pre-lease payment present valued after-tax profits (profits in excess of normal return on capital). This computation is done in two stages. First, the investor's present valued after-tax profits are computed assuming no lease payment. The investor's post-lease after-tax profits are then set to a user-supplied fraction of this amount. The program then iteratively solves for the actual lease payment which will produce this difference as the investor's profit after taxes. Iteration is necessary since the tax stream will be affected by the presence of a lease payment.

The program thus takes a user-specified proportion of the pre-lease payment profits and assumes that this percentage of the economic rent associated with the project is turned over to the federal government in the form of a lease bid two years prior to initial production. The present valued profits after lease payment are then recomputed in their entirety, with the lease payment incorporated in the cash flow.

The user then may examine these results (the program is available on time sharing) and modify the amount of reinjection as he desires and repeat the entire process. Results of a sample run are given in Figure 2.2.

For the purpose of this study, a series of runs of the Offshore Development Model was made, varying what appear to be the key variables in determining the costs associated with developing a domestic offshore find:

1. original oil in place
2. distance to landing point
3. water depth
4. platform design wave height.

Since these location parameters, if you like, were the primary focus of this particular analysis, the other major geological and financial variables were fixed at the values shown in the table on page 45. A complete list of the input values is shown in the sample run displayed in Figure 2.2.

These values define a rather average pure gas drive reservoir. Since in this section we are concentrating entirely on primary recovery, zero gas reinjection was specified, in which case, according to the Muskat-Hoss model, the primary oil recovered is about 17% of the

Figure 2.2

SUMMARY OF CASE INPUTS

STRATEGY VARIABLES:

MINIMUM NUMBER FIELD PLATFORMS USED......	2	MINIMUM NUMBER WELLS PER PLATFORM USED...	24
MAXIMUM NUMBER FIELD PLATFORMS USED......	4	MAXIMUM NUMBER WELLS PER PLATFORM USED...	24
FIELD PLATFORM INCREMENT FOR ITERATION...	1	WELLS PER PLATFORM INCR. FOR ITERATION...	4
MAXIMUM FIELD PLATFORMS ADDED PER YEAR...	5	MAXIMUM PUMP STATIONS ALLOWED (WATER)....	5
MAXIMUM PUMP STATIONS ALLOWED (LAND).....	0		

RESERVOIR VARIABLES:

OIL IN PLACE............................	500 MMBBL	GAS IN PLACE............................	500 MMMCF
RESERVOIR TEMPERATURE...................	200 DEG F	RESERVOIR INITIAL PRESSURE..............	5,000 PSIA
OIL ALLOWABLE PER WELL..................	10 MBPD	GAS ALLOWABLE PER WELL..................	100 MMCFPD
OIL API NUMBER..........................	30.000	GAS SPECIFIC GRAVITY....................	0.600
OIL VISCOSITY...........................	2.000 CP	RESERVOIR POROSITY......................	14.000 %
RESERVOIR ABSOLUTE PERMEABILITY..........	0.100 DAR	RESIDUAL (CONNATE) WATER SATURATION......	30.000 %
RESIDUAL OIL SATURATION--WATER FLOOD.....	20.000 %	RESIDUAL OIL SATURATION--GAS FLOOD.......	20.000 %
FRACTION OF EXPANDED GAS CAP PRODUCED....	20.000 %	MAXIMUM GAS REINJECTION.................	0.000 %
GAS SOLUTION DRIVE PRESSURE DECREMENT....	50.000 PSIA	WATER COMPRESSIBILITY (X 1000000)........	3.200 /PSIA
OIL COMPRESSIBILITY (X 1000000)..........	20.000 /PSIA	FORMATION COMPRESSIBILITY (X 1000000)....	4.000 / PSIA
MODEL EMPLOYED..........................	WATER DRIVE	FORMATION ROCK TYPE.....................	CEM. SS,OOLITE OR SMALL VUGS
NUMBER OF POOLS HOLDING RESERVES.........	1		
FORMATION THICKNESS.....................	40 FT		

FIELD VARIABLES:

DEPTH OF SEA OVER POOLS.................	300 FT	KICK-OUT DRILLING DEPTH (BELOW SEA FLOOR)	1,500 FT
DEPTH OF FORMATION (BELOW SEA FLOOR).....	10,000 FT	DESIGN WAVE HEIGHT......................	75 FT
MAXIMUM DRILLING SLANTANGLE.............	0.785 RAD		

TRANSPORT VARIABLES:

DISTANCE TO REFINERY PORT VIA SEA........	75 MI	OIL PIPELINE DISTANCE--WATER ROUTE.......	75 MI
REFINERY PORT DRAFT LIMIT................	41 FT	OIL PIPELINE DISTANCE--LAND ROUTE........	0 MI
SINGLE BUOY MOORING DISTANCE TO SHORE....	0 MI	GAS PIPELINE DISTANCE--WATER ROUTE.......	75 MI
SINGLE BUOY MOORING DISTANCE ON SHORE....	0 MI	GAS PIPELINE DISTANCE--LAND ROUTE........	0 MI
LOST MANEUVERING TIME IN PORT............	0.850 DAYS	MAXIMUM PIPELINE WALL THICKNESS..........	0.750 IN
LAY BARGE & PLATFORM TOW DISTANCE........	1,500 MI	YIELD STRESS OF PIPELINE STEEL...........	60,000 PSIA
REGISTRY OF TANKERS.....................	USA	TERMINAL CONSTRUCTION NECESSARY..........	NONE
BOTTOM TYPE.............................	SAND		

FINANCIAL VARIABLES:

BASE STEEL COST.........................	300 $/TON	PLATFORM MOBILIZATION COST...............	1,000 $000
OIL ROYALTIES...........................	1.250 $/BBL	DEBT TO EQUITY RATIO.....................	0.000
GAS ROYALTIES...........................	0.235 $/MCF	BORROWING INTEST RATE....................	0.000 %
LEASE PAYMENT FRACTION OF PROFITS........	75.000 %	INVESTOR OPPORTUNITY COST OF CAPITAL.....	10.000 %
PERCENT BAD WEATHER DAYS PER YEAR........	20.000 %		
OIL PRICE (1974)........................	10.000 $/BBL	GAS PRICE (1974)........................	1.879 $/MCF

SUMMARY OF CAPITAL & OPERATING COSTS

YEAR	CAPITAL COSTS: FIELD PROD	CAPITAL COSTS: TANKER TERMINAL	CAPITAL COSTS: OIL PIPELINE	CAPITAL COSTS: GAS PIPE W/O OIL	CAPITAL COSTS: GAS PIPE W/ OIL	OPERATING COSTS: FIELD PROD	OPERATING COSTS: TANKER OPER	OPERATING COSTS: OIL PIPELINE	OPERATING COSTS: GAS PIPE W/O OIL	OPERATING COSTS: GAS PIPE W/ OIL
1977	9.81E+07	2.18E+07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1978	5.35E+06	0.00E+00	3.63E+07	3.08E+07	3.08E+07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1979	0.00E+00	0.00E+00	1.43E+06	3.95E+06	3.93E+06	4.13E+06	1.14E+07	9.09E+05	7.69E+05	7.69E+05
1980	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	7.11E+06	9.44E+05	8.68E+05	8.67E+05
1981	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.87E+06	9.44E+05	8.68E+05	8.67E+05
1982	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.77E+06	9.44E+05	8.68E+05	8.67E+05
1983	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.68E+06	9.44E+05	8.68E+05	8.67E+05
1984	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.57E+06	9.44E+05	8.68E+05	8.67E+05
1985	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.53E+06	9.44E+05	8.68E+05	8.67E+05
1986	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.50E+06	9.44E+05	8.68E+05	8.67E+05
1987	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.48E+06	9.44E+05	8.68E+05	8.67E+05
1988	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.45E+06	9.44E+05	8.68E+05	8.67E+05
1989	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.44E+06	9.44E+05	8.68E+05	8.67E+05
1990	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.33E+06	9.44E+05	8.68E+05	8.67E+05
1991	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.33E+06	9.44E+05	8.68E+05	8.67E+05
1992	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.33E+06	9.44E+05	8.68E+05	8.67E+05
1993	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.33E+06	9.44E+05	8.68E+05	8.67E+05
1994	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.32E+06	9.44E+05	8.68E+05	8.67E+05
1995	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.31E+06	9.44E+05	8.68E+05	8.67E+05
1996	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.30E+06	9.44E+05	8.68E+05	8.67E+05
1997	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.23E+06	9.44E+05	8.68E+05	8.67E+05
1998	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.23E+06	9.44E+05	8.68E+05	8.67E+05
1999	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.24E+06	9.44E+05	8.68E+05	8.67E+05
2000	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E+06	6.22E+06	9.44E+05	8.68E+05	8.67E+05

SUMMARY OF FIELD AND TRANSPORT PARAMETERS

YEAR	TOTAL PLATS	TOTAL WELLS	OIL PROD	GAS PROD	WATER PROD	TANKER DWT	NO. TKR	NO. TRPS	CHARTER RATE	OIL/ WATER	OIL/ LAND	GAS/ WATER	GAS/ LAND
1979	4	76	7.958E+07	6.089E+10	0.000E+00	40000	2	154	8.60E+06	1	0	1	0
1980	4	76	4.085E+07	2.858E+10	0.000E+00	40000	1	158	4.33E+06	1	0	1	0
1981	4	76	3.037E+07	2.143E+10	0.000E+00	40000	1	118	4.08E+06	1	0	1	0
1982	4	76	2.602E+07	1.933E+10	0.000E+00	40000	1	101	3.98E+06	1	0	1	0
1983	4	76	2.204E+07	1.746E+10	0.000E+00	40000	1	86	3.89E+06	1	0	1	0
1984	4	72	1.749E+07	1.485E+10	0.000E+00	40000	1	68	3.78E+06	1	0	1	0
1985	4	72	1.598E+07	1.451E+10	0.000E+00	40000	1	62	3.75E+06	1	0	1	0
1986	4	72	1.473E+07	1.443E+10	0.000E+00	40000	1	57	3.72E+06	1	0	1	0
1987	4	72	1.363E+07	1.449E+10	0.000E+00	40000	1	53	3.69E+06	1	0	1	0
1988	4	72	1.261E+07	1.464E+10	0.000E+00	40000	1	49	3.67E+06	1	0	1	0
1989	4	72	1.169E+07	1.486E+10	0.000E+00	40000	1	46	3.65E+06	1	0	1	0
1990	4	48	7.244E+06	9.715E+09	0.000E+00	40000	1	28	3.54E+06	1	0	1	0
1991	4	48	7.101E+06	9.341E+09	0.000E+00	40000	1	28	3.54E+06	1	0	1	0
1992	4	48	7.163E+06	9.505E+09	0.000E+00	40000	1	28	3.54E+06	1	0	1	0
1993	4	48	7.056E+06	9.672E+09	0.000E+00	40000	1	28	3.54E+06	1	0	1	0
1994	4	48	6.809E+06	9.874E+09	0.000E+00	40000	1	27	3.53E+06	1	0	1	0
1995	4	48	6.463E+06	9.947E+09	0.000E+00	40000	1	25	3.52E+06	1	0	1	0
1996	4	48	6.117E+06	1.005E+10	0.000E+00	30000	1	32	3.51E+06	1	0	1	0
1997	4	29	3.679E+06	5.892E+09	0.000E+00	30000	1	20	3.44E+06	1	0	1	0
1998	4	29	3.779E+06	5.441E+09	0.000E+00	30000	1	20	3.44E+06	1	0	1	0
1999	4	29	3.889E+06	5.364E+09	0.000E+00	30000	1	21	3.45E+06	1	0	1	0
2000	4	29	3.660E+06	5.065E+09	0.000E+00	30000	1	19	3.44E+06	1	0	1	0

MISCELLANEOUS SYSTEMS PARAMETERS AND PRESENT VALUE TOTALS

OIL RECOVERY (%)	69.590	PV OIL PRODUCTION (SOLD MBBLS)	132,881
GAS RECOVERY (%)	68.984	PV GAS PRODUCTION (SOLD MMCF)	110,730
OIL PIPELINE HORSEPOWER/STATION/LINE (WATER)	4,410	PV FIELD DEVELOPMENT COSTS ($000)	92,807
OIL PIPELINE HORSEPOWER/STATION/LINE (LAND)	0	PV TRANSPORTATION COSTS--OPTIMAL ($000)	54,481
GAS PIPELINE HORSEPOWER/STATION/LINE (WATER)	12,077	PV FEDERAL AND STATE INCOME TAXES ($000)	383,461
GAS PIPELINE HORSEPOWER/STATION/LINE (LAND)	0	PV LEASE PAYMENTS ($000)	645,247
OIL PIPELINE DIAMETER (WATER)	20	PV OIL ROYALTY PAYMENTS ($000)	166,102
OIL PIPELINE DIAMETER (LAND)	0	PV GAS ROYALTY PAYMENTS ($000)	26,021
GAS PIPELINE DIAMETER (WATER)	12	PV TOTAL NATIONAL COSTS ($000)	147,288
GAS PIPELINE DIAMETER (LAND)	0	PV INVESTOR PROFITS ($000)	168,866
BREAK-EVEN OIL PRICE-UNADJUSTED ($/BBL)	1.108	PV GROSS REVENUES ($000)	1,536,989
BREAK-EVEN OIL PRICE-W/ LEASE & ROY ($/BBL)	7.410	PV TANKER SYSTEM COST ($000)	53,442
BREAK-EVEN OIL PRICE-UNADJ LESS GAS PIPE $/B.	0.913	PV OIL PIPELINE SYSTEM COST ($000)	28,501
BREAK-EVEN OIL PRICE-ADJ & NO GAS PIPE $/B	7.215	PV GAS PIPELINE SYSTEM W/ TANKERS ($000)	25,993
NUMBER OF PUMP STATIONS ON WATER ROUTE (GAS)	1	DISTANCE BETWEEN PUMP STATIONS (GAS/WATER)	75.000
NUMBER OF PUMP STATIONS ON WATER ROUTE (OIL)	1	DISTANCE BETWEEN PUMP STATIONS (OIL/WATER)	75.000
NUMBER OF PUMP STATIONS ON LAND ROUTE (GAS)	0	DISTANCE BETWEEN PUMP STATIONS (GAS/LAND)	0.000
NUMBER OF PUMP STATIONS ON LAND ROUTE (OIL)	0	DISTANCE BETWEEN PUMP STATIONS (OIL/LAND)	0.000
OIL SHIPPED VIA	PIPELINE		

RESERVOIR MODEL COMPLETION CONDITION: INSTABILITY ON S_O

VALUES OF MAJOR INPUT PARAMETERS
NOT VARIED DURING RUN

Type of drive	Solution gas
Number of individual reservoirs	1
Initial gas/oil ratio	100:1
Reservoir temperature	200°F
Initial pressure	5,000 psi
Formation depth	10,000 feet
Formation thickness	40 feet
Absolute permeability	100 millidarcies
Porosity	14%
Rock type	Cemented sandstone
Connate water	30%
Oil API	30
Gas specific gravity	0.6
Bottom type	Sand
Investor real cost of capital	10%
Real oil price (1974 dollars)	10.00/barrel
Real gas price (1974 dollars)	1.88/Mcf
No ad valorem tax	
No allowables	
No gas reinjection	
Producing wells per platform	20

initial oil in place. Gas recovery is about 67%. In actual fact, such a field would be subject to considerable secondary effort which could easily double or triple the oil recovery. For now, however, we are dealing strictly with primary oil.

The variables of direct interest to us in this section were iterated over the following values. Original oil in place was varied from two billion barrels to fifty million barrels (2.0×10^9, 1.0×10^9, $.5 \times 10^9$, $.2 \times 10^9$, $.1 \times 10^9$, $.05 \times 10^9$). Distance offshore was varied from twenty-five miles to seventy-five miles to 150 miles and, in the case of Alaska, 1,500 miles. Water depths of 150 feet, 300 feet, and 450 feet were examined. These combinations of depths and design waves cover the range from the Gulf of Mexico to the northern North Sea and represent the usable limits of our present platform costing model.

Tables 2.2 through 2.4 display some of the results. These tables show an estimate of the unit national cost of developing each of the hypothetical finds studied. More precisely, the numbers shown are the landed price of oil the developer would have to obtain to break even at 10% on the resource costs associated with the profit maximizing strategy given the $10.00 oil price assumed. As such these numbers are upper bounds on the actual break-even price for if oil is priced well above the break-even price, it will generally pay the present value maximizing developer to increase his unit cost to bring the oil out faster.

They are also upper bounds in the sense that they give no credit to the gas found and no credit to secondary oil.

The numbers shown are the estimated resource cost of development to the nation. They do not include lease bids, royalties, or taxes, which are not a cost to the nation of landing the oil but rather national income transfers. That is, the payments to the government do not represent the diversion of resources to OCS oil production with the loss of the alternative output of these resources in other employment opportunities. Rather, they represent shifts in income from one piece of the pie to another.

Nor do the numbers include geophysical survey and exploratory drilling expenses. The unit exploration costs will, of course, depend on what's found. As we shall see,

TABLE 2.2

UNIT NATIONAL COSTS LANDED - ($/ BARREL)

GAS DRIVE, NO RESTRICTIONS ON ALLOWABLES, DISTANCE TO LANDFALL = 25 Miles

		ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS					
		2.0	1.0	.5	.2	.1	.05
Water Depth = 150'							
Design	50'	.67	.91	1.54	2.56	3.80	6.27
Wave	75'	.69	.93	1.57	2.61	3.87	6.41
Height	100'	.71	.96	1.43	2.68	3.95	6.58
Water Depth = 300'							
Design	50'	.77	1.02	1.51	2.83	4.15	X
Wave	75'	.89	1.17	1.72	2.95	4.65	X
Height	100'	1.15	1.34	2.13	3.47	5.65	X
Water Depth = 450'							
Design	50'	1.05	1.36	1.97	3.26	5.24	X
Wave	75'	1.55	2.05	2.89	4.86	8.34	X
Height	100'	2.44	3.32	5.14	8.54	X	X

X implies field could not be profitably developed at $10.00 oil, $1.87 Gas, and 10% real cost of capital

Underlining implies program chose to land oil by tanker

TABLE 2.3

UNIT NATIONAL COSTS LANDED - ($/ BARREL)

GAS DRIVE, NO RESTRICTIONS ON ALLOWABLES, DISTANCE TO LANDFALL = 75 Miles

		ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS					
		2.0	1.0	.5	.2	.1	.05
Water Depth = 150'							
Design	50'	.74	1.02	1.54	2.49	3.80	X
Wave	75'	.75	1.04	1.57	2.53	3.87	X
Height	100'	.77	1.07	1.61	2.57	3.95	X
Water Depth = 300'							
Design	50'	.83	1.13	1.69	2.68	4.15	X
Wave	75'	.96	1.29	1.89	2.93	4.65	X
Height	100'	1.21	1.46	2.05	3.45	5.65	X
Water Depth = 450'							
Design	50'	1.12	1.35	1.92	3.24	5.24	X
Wave	75'	1.61	2.17	2.89	4.84	X	X
Height	100'	2.51	3.44	5.14	8.52	X	X

X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital

Underlining implies program chose to land oil by tanker

TABLE 2.4

UNIT NATIONAL COSTS LANDED - ($/ BARREL)

GAS DRIVE, NO RESTRICTIONS ON ALLOWABLES, DISTANCE TO LANDFALL = 150 Miles

ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS

		2.0	1.0	.5	.2	.1	.05
Water Depth = 150'							
Design	50'	.83	1.19	1.54	2.50	3.80	X
Wave	75'	.85	1.21	1.57	2.53	3.87	X
Height	100'	.87	1.24	1.61	2.57	3.95	X
Water Depth = 300'							
Design	50'	.93	1.30	1.69	2.68	4.15	X
Wave	75'	1.05	1.46	1.77	2.93	4.65	X
Height	100'	1.31	1.63	2.09	3.45	5.65	X
Water Depth = 450'							
Design	50'	1.22	1.64	1.96	3.24	5.25	X
Wave	75'	1.71	2.00	2.93	4.84	X	X
Height	100'	2.61	3.55	5.18	8.52	X	X

X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital

Underlining implies program chose to land oil by tanker

industry is currently spending something less than 125 million dollars per year on geophysical surveying of the OCS and something less than one billion dollars per year to drill something over 500 exploratory wells. Assuming this level of expenditure in real terms is maintained over the next ten years and assuming, just for the purposes of obtaining a rough idea of the magnitude involved, that the oil which is found is brought out on a uniform basis over a fifteen-year period commencing three years after the exploratory expenditure, then at 10% real cost of capital the unit exploratory cost as a function of total discoveries over this ten-year period is shown in the following table.

AMOUNT OF RECOVERABLE OIL DISCOVERED

(Billions of Barrels)

10	20	50	100	200
$2.45	$1.20	$.60	$.30	$.15

In other words, if the Mobil predictions prove to be true, we are talking a good deal less than $1.00 per barrel finding cost. If the more optimistic U.S.G.S. estimates prove out, then finding costs could easily be less than 50¢ per barrel. In the extremely difficult Scottish North Sea, where exploratory wells can cost up to ten million dollars, approximately 150 wells have discovered at least fifteen billion barrels of oil, for a unit finding cost of at most 25¢ per barrel. At the other extreme, a several hundred million dollar exploratory program off the east coast of Canada has yet to establish commercial quantities of petroleum. In summary, then, a reasonably successful exploratory drilling program in frontier areas on the OCS will have a unit real cost of $1.00 per barrel or less. A completely unsuccessful program could involve the expenditure of five to ten billion dollars with no return.

Returning to the development costs, there are several interesting points to be noticed about Tables 2.2 through 2.4.

1. The dependence on distance to landfall is not particularly striking, especially for the smaller fields. While going from twenty-five miles offshore to seventy-five miles offshore increases unit cost about ten cents per barrel, going from seventy-five miles offshore to 150 miles offshore results in little change in unit cost for all but the largest fields. The reason is that the model believes that tanker transport is cheaper than pipelines as field size decreases and distance to shore increases. The hypothetical discoveries which the program lands by tanker are underlined in the tables. The difference between the cost of seventy-five miles of tanker transport and the cost of 150 miles is quite small due to the fact that the tankers are spending most of their time at either end of these extremely short routes.*

2. In general, the dependence of unit costs on distance offshore by itself, or design wave height by itself, or even water depth by itself is not too impressive. It is only when they are

*The costing routine is not sensitive to the added expense associated with crew and supply transport to the fields further offshore. This will usually not be significant.

considered in combination and it is realized that these variables are usually not independent, all tending to increase at the same time, that striking differences in unit costs are obtained for a given field size. The difference between the most favorable combination of water depth and design wave height studied (150 feet and fifty feet) and the least favorable studied (450 feet and 100 feet) is about a factor of four in unit costs, holding everything else constant. Of the three locational variables studied, water depth appears to be the single most important.

3. Certainly the most striking result of these runs is the implication that in terms of national cost, offshore oil can be quite cheap. When one compares the unit costs shown for at least the larger finds studied with the present cost to the nation of foreign crude, something over $10.00 per barrel, then one comes quickly to the conclusion that the loss in national market income associated with not developing a large offshore find on the OCS can easily approach seven or eight dollars per barrel not landed. Assuming foreign oil will cost the nation $10 per barrel real (1974 dollars) through the future, for the largest hypothetical find we

have studied--two billion barrels in place--this would imply a loss in present valued national income of from 2.6 to 2.2 billion dollars, depending on the design wave height and water depth.

However, according to the model, the unit costs start increasing rather rapidly as one moves to the smaller fields, for at least the less favorable combinations of water depth and wave height. At $10 per barrel oil and $1.87 per Mcf gas, a fifty million barrel in place find with our hypothetical reservoir characteristics can only be profitably developed at the lower end of the water depth and distance offshore range. A 100 million barrel find just about breaks even at the higher end of the range. Remember we are crediting the discovery for its primary production only. The possibilities for secondary and tertiary increments may push these lower limits on field size down by as much as a factor of two. Also remember these are completely isolated discoveries in the sense that they are unable to take advantage of economies of scale associated with sharing pipelines with neighboring fields.

It is also important to keep in mind that the model only considers conventional space frame, steel platform technology. It does not consider concrete platforms or subsea completions--both of which may be superior to conventional technology for certain unfavorable combinations of distance offshore, water depth, and design wave height.

These caveats notwithstanding, it is clear from the results that we do have that if you find enough oil almost anywhere on the U.S. Lower 48 continental shelf, it will be cheap oil.*

The case of Gulf of Alaska oil is not that much different. Table 2.5 displays the results of a series of runs meant to be representative of a hypothetical find in the Gulf of Alaska. The distance to landfall in the Puget Sound area has been set at 1,500 miles. Oil and gas pipelines were disallowed for this exercise. The design wave height, seventy-five feet, is based on TetraTech studies of the 100-year wave in the area done for the Council on Environmental Quality (14). The cost of each platform has been arbitrarily increased by four million dollars to cover increased mobilization and downtime expenses. Ice is not expected to be a problem offshore in the Gulf of Alaska. The results indicate that this oil will be approximately 50¢ per barrel more expensive to land in the Lower 48 than a similar reservoir on the

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*As long as the OPEC cartel is not broken. The resource cost of producing Persian Gulf crude and landing it in the United States is something less than $1.50.

TABLE 2.5

UNIT NATIONAL COSTS LANDED - ($/BARREL)

GULF OF ALASKA, GAS DRIVE, NO ALLOWABLES DISTANCE TO LANDFALL = 1500 Miles
DESIGN WAVE HEIGHT = 75

	ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS				
	2.0	1.0	.5	.2	.1
Waterdepth = 150	1.31	1.56	2.12	3.20	5.05
Waterdepth = 300	1.46	1.73	2.37	3.61	5.84
Waterdepth = 450	2.00	2.53	3.53	5.51	X

X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital

Lower 48 continental shelf. Not surprisingly, 50¢ per barrel is about the cost of transporting oil 1,500 miles in small domestic flag tankers. In summary, this oil too can be quite cheap, depending on the size of the reservoir.

Combining these results with the projections of the amount of oil which will be discovered on the OCS can lead to some extremely large numbers with respect to national income. The mid-range of the present U.S.G.S. estimate is 100 billion barrels. If on the average such an amount of oil had a landed resource cost of $3.00 per barrel (i.e. was recovered from fields which for the most part had an original oil in place of greater than 500 million barrels, or a primary recoverable of about 100 million barrels) then we are talking of a difference in real national income between developing such a resource and not developing it of about 225 billion dollars in present value terms assuming a social cost of capital of 10% real and a twenty-year production life, or on an annual basis some thirty-five billion dollars per year for twenty years. To put it in other terms, this difference in national income is equivalent to handing every woman, man, and child in the United States a little over $1,000 in real income right now on a one-shot basis, or an extra $160 per year for twenty years. This figure represents roughly 3% of the entire market income of the United States over this period. It is difficult to conceive of any other single activity where such impacts are possible.

Of course, if less oil than the U.S.G.S. projects is found or if this oil tends to be found in smaller reservoirs than the bulk of past oil, the net impact of OCS oil could drop precipitously. It is worth noting that most of the private estimates of future OCS discoveries are about one-half the current U.S.G.S. estimates. In any event, it is clear that if any of the projections are anywhere near correct, in dealing with OCS petroleum, we are talking about a very substantial amount of national income.

2.3 The Peculiarities of the Gulf of Mexico

In the public debate concerning OCS leasing, it is common practice to extrapolate Gulf of Mexico experience to the potential frontier areas. This is understandable enough since almost all the domestic experience with offshore oil exploration and production has taken place in the Gulf. However, we should be aware in so doing that the Gulf is a rather unusual province from the point of view of petroleum geology.

Notice that none of the top eleven fields of Table 2.1 are in the Gulf. In fact, the largest field in the Gulf, Bay Marchand, ranks about twenty-third on the domestic original oil in place list, and most of the Gulf fields are much smaller than this.

The following table shows a list of the current OGJ estimates of ultimate recovery for the ten largest Gulf fields and compares them with preliminary--and for the most part, conservative--estimates of recoverables from the ten largest North Sea fields.

ULTIMATE RECOVERY, MILLIONS OF BARRELS

Gulf		North Sea	
Bay Marchand, Block 2	650	Statfjord	3,500
South Pass, Block 24	490	Brent	2,000
West Delta, Block 30	450	Ninian	2,000
Grand Isle, Block 43	410	Forties	1,800
South Pass, Block 27	385	Ekofisk*	1,200
Grand Isle, Block 16	350	Piper	1,000
Main Pass, Block 41	280	Beryl	700
West Delta, Block 73	274	Thistle	600
Main Pass, Block 69	260	Hutton	500
Ship Shoal, Block 208	225	Dunlin	500

*Recoverables for the entire Ekofisk complex, six structures, are currently put at 2.5 billion barrels.

The reason for the fact that the Gulf fields are small by offshore standards is almost certainly the preponderance of salt domes as the trapping mechanism. Salt domes tend to be limited in areal extent and to break up the larger anticlinal structures in which most oil is found elsewhere. This fact has several implications.

1. Gulf OCS oil tends to be relatively expensive considering the rather mild depths, wave heights, and distances to shore.

2. Because of the complex geology associated with salt domes and the variety of different and localized places oil can be found in the vicinity of a salt dome, the exploratory drilling effort associated with these structures is considerably greater than that associated with anticlines. One industry source writes:

   > The acreage evaluated by each exploratory well can vary significantly dependong on the knowledge of the area, type of geological formation and structure, and position of the lease grid on the structure. The geological configuration in the Gulf of Mexico probably is among the most complex that will be found on the OCS because of the large percentage of piercement salt dome prospects. In one, fifteen wells were drilled on a salt dome structure located within one tract in an effort to delineate the productive area. Thus, the worst case for tract evaluation in the Gulf area would be where a salt dome centered inside a 5,000 acre tract would require at least ten wells for full geological evaluation. In this case, one well would evaluate 500 acres.
   >
   > The best case for geological evaluation can be made where four 5,000 acre tracts are located on a large anticlinal structure and one well is drilled near the common corners

> of the block. For exploratory purposes this one well would evaluate 20,000 acres. Present geological indications are that such very large anticlines will be found in the Atlantic, the Gulf of Alaska, and possibly off Southern California. It is the opinion of some industry representatives that in areas where large structures are identifiable and the geology is not complex, three to four wells per structure would be adequate to determine the productive potential of the prospect (15).

We will have reason to refer back to the rather unusual exploratory characteristics of the Gulf of Mexico in our discussion of public exploratory drilling.

The final unusual characteristic of the Gulf of Mexico which we need to keep in mind has almost nothing to do with the geology characteristics of the region, but rather of a historically based regulatory policy. Among the important assumptions underlying the unit resource costs shown in Tables 2.2 through 2.5 is the premise that there are no legal (as opposed to purely physical) restrictions on the rate at which the wells are produced. For the base reservoir we have chosen to investigate, the wells are typically producing at rates of three to four thousand barrels per day. Such production rates and higher are quite common in the Middle East and North Sea. On the United States OCS, however, it is common practice to regulate reservoir and per-well production, often limiting production rates to a few hundred barrels per well-day. The ostensible argument for this regulation is that too rapid withdrawal will decrease total recovery. The argument is an extremely weak one on three grounds:

a. For most reservoirs, total recovery is a very weak function of rate of withdrawal, especially when secondary operations are taken into account.*

b. From an economic viewpoint, the objective function which will maximize real national wealth is not maximum recovery but maximum present valued recovery less present value of resource costs.

c. In the absence of a common pool problem, there is no reason to believe that the operators will produce in a manner such as to reduce present valued national income, for to do so would decrease the operators' present valued profits. The common pool problem, when it crops up on the OCS, can be more easily and more directly handled by the simple requirement that all reservoirs must be operated in a unitized fashion.

The lie to the argument for reservoir production regulation is given by the manner in which it has been enforced in the past in the OCS. In general the per-well allowables have been set as a simple function of either the water depth or the well depth or both. These two variables by themselves in no way characterize a given reservoir response to a particular production scheme. In

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*For some reservoirs, ultimate recovery can be increased slightly by increasing withdrawal rate.

order to do that we would at the very minimum have to know the type of drive, the initial pressure, initial gas/oil ratio, oil and gas viscosity, and permeability. Until the recent changes to OCS Order 11, this information was not even available to the U.S.G.S., which sets the allowables. It is fairly clear that the policy of setting allowables is a historic holdover from land practice, where the common pool argument held more force.

However, since land practice, at least in Louisiana, was to base allowables on well depth, a pseudo-economic basis having nothing to do with reservoir response, one suspects that even on land, this regulation functioned mainly as a form of proration, an attempt to maintain prices by holding up on supply.

Given the foregoing and, despite the foregoing, given the likelihood of allowables being set on future OCS discoveries, it is of interest to examine the effect of such regulation on the economics of our hypothetical find. Table 2.6 repeats the earlier seventy-five mile offshore runs (Table 2.3) with one exception. The daily production rate of each well has been limited to 1000 barrels per day. The result, as can be seen by comparing Tables 2.6 and 2.3 , is to increase the unit national cost of landing respective finds by about 20%. The corresponding decrease in national income can be rather sizable. For our two billion barrel in place find, this difference is about 500 million dollars, present value,

TABLE 2.6

UNIT NATIONAL COSTS LANDED - ($/BARREL)

GAS DRIVE, OIL ALLOWABLE: 1000 BARRELS PER DAY, GAS ALLOWABLE, 10 MMCFD, DISTANCE TO LANDFALL = 75 Miles

		ORIGINAL OIL IN PLACE IN BILLIONS OF BARRELS				
		2.0	1.0	.5	.2	.1
Water Depth = 150'						
Design Wave Height	50'	.85	1.15	1.71	2.75	4.29
	75'	.88	1.18	1.75	2.80	4.36
	100'	.90	1.21	1.80	2.87	4.45
Water Depth = 300'						
Design Wave Height	50'	.97	1.28	1.91	3.03	4.67
	75'	1.12	1.46	2.18	3.43	5.19
	100'	1.42	1.81	2.73	4.23	6.25
Water Depth = 450'						
Design Wave Height	50'	1.31	1.67	2.52	3.90	5.81
	75'	2.22	2.76	3.70	5.70	X
	100'	4.05	4.77	6.07	X	X

X implies field could not be profitably developed at $10.00 oil, $1.87 gas, and 10% real cost of capital which is about the same as the loss associated with going from this find in a water depth of 150 feet and wave height of fifty feet to the same find in a water depth of 450 feet with a design wave height of 100 feet. Primary recovery for this particular gas drive reservoir is completely insensitive to withdrawal rate and it pays the operator to produce this field quite rapidly if he is allowed to. Thus, the allowable constraint is quite expensive. For natural water drive reservoirs, the present value maximizing production rate may be considerably slower and the cost of enforcing allowables correspondingly less.

To study this issue we have made a series of runs of the Offshore Development Program's water drive model. In these runs all the reservoir parameters were kept the same as our earlier gas drive fields with the exception that the reservoir was endowed with an active water drive.*

The response of this reservoir is qualitatively quite different from that of our earlier purely gas drive situation. Water is a much more efficient expulsion mechanism than gas but it typically operates at much slower rates. The result is much higher recoveries and much longer primary reservoir life. While the Offshore Development Model depletes the earlier gas drive reservoirs of primary oil in eight years or less, the larger water

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*To be more precise, an infinite aquifer, Hurst-Van Everdingen edge drive.

drive reservoirs are still producing, albeit at low rates, after thirty years. The resulting primary recovery is much higher, in the neighborhood of 65% as opposed to the earlier 17% for primary production of the same reservoir under pure gas drive. However, the differences in present values are not as great as this due to the lower withdrawal rates under water drive. In general, our water drive reservoir represents, for its size, an extremely fortunate combination of characteristics. In the real world, only a small proportion of major U.S. reservoirs have primary production in excess of 50%.*

The water drive results for a moderately difficult combination of distance to landfall, design wave height, and water depth are compared with the corresponding gas drive results in Table 2.7 . The unit national costs are roughly half those of the same gas drive field and the change in national income is about doubled. The fifty million barrel in place water drive field is comfortably in the black while the correspondingly sized gas drive field could not break even at 10%. The peak per-well production rate of the water drive reservoirs is roughly one-fourth that of their gas drive counterparts and in all cases was under 1,000 barrels per day. Thus, a 1,000 barrel per day allowable would have no effect on

*It should be pointed out, however, that with sufficient investment in water injection, production from the gas drive field can be made to look rather similar to that from the water drive field.

TABLE 2.7

COMPARISON OF PURE GAS DRIVE AND WATER DRIVE RUNS

DISTANCE TO LANDFALL = 75 MILES
WATER DEPTH = 300'
DESIGN WAVE HEIGHT = 75'
NO ALLOWABLES

	ORIGINAL OIL IN PLACE (10^9 BARRELS)					
	2.0	1.0	.5	.2	.1	.05
UNIT NATIONAL COST						
Gas Drive	.96	1.29	1.89	2.68	4.65	-
Water Drive	.48	.65	.91	1.65	2.49	3.16
A NATIONAL INCOME* (P.V. @ 10% REAL-BILLIONS OF 1974 DOLLARS)						
Gas Drive	2.7	1.3	.7	.23	.10	-
Water Drive	4.4	2.2	1.0	.55	.24	.11
PRIMARY OIL RECOVERY						
Gas Drive	17%	17%	17%	17%	17%	-
Water Drive	65%	68%	69%	70%	70%	62%
NUMBER OF PLATFORMS						
Gas Drive	9	5	3	1	1	-
Water Drive	9	5	4	2	1	1
TRANSPORTATION MODE						
Gas Drive	Pipe	Pipe	Tank	Tank	Tank	-
Water Drive	Pipe	Pipe	Pipe	Tank	Pipe	Tank
PRIMARY FIELD LIFE						
Gas Drive	8	6	5	4	3	-
Water Drive	40	40	27	19	16	10

* Assuming Cost to nation of alternative oil is \$10/bbl,altervative gas \$1.88/Mcf.

production, and hence imply no loss in national income. However, an allowable in the neighborhood of a few hundred barrels, as is common in the Gulf of Mexico, would.

All our earlier statements about the cheapness of large reservoir OCS oil relative to OPEC oil hold a fortiori for this very favorable set of reservoir characteristics.

CHAPTER 3

THE PRESENT SITUATION AND SOME PROBLEMS

3.1 The Present Bonus Bid System

The present U.S. OCS petroleum management policy is based on:

1. Non-exclusive permitting of geophysical exploration for a nominal fee. The geophysical work is often done by consortia of oil companies, "group shoots", each of whose members is required not to disclose any of the data. A consortium may be made up of as many as twenty companies. Sometimes the Department of Interior buys a share in these consortia and is bound to the same disclosure rules. Under a very recent Department of Interior ruling, permit holders may be required to supply results of surveys to the government. The government must maintain the confidentiality of such data.

2. Sealed bid auction of leases awarding exclusive exploratory drilling and extraction rights by tract. Lessee is required to pay a fixed royalty (set at approximately 16-2/3% landed value) on each unit of oil and gas produced, pay a nominal yearly rental, and abide by U.S.G.S. safety and environmental regulations.

In case of abandonment, the tract reverts back to the government. The tracts are generally about 5,000 acres in extent, laid out on a rectangular three mile by two mile grid. The Bureau of Land Management has the right to reject the high bid and not lease the tract but can accept only the highest bid offered on each tract. This policy is known as bonus bidding. This policy evolved from onshore practice with little apparent conscious analysis of the alternatives.

As we shall see, in a world without uncertainty, the bonus bid has much to recommend itself. However, there may be reason to suspect that the bonus bid system may be in trouble from the point of view of preventing a large-scale transfer of income from the public to the developer.

This was almost certainly <u>not</u> the case through 1972. Table 3.1 shows the present value as of 1972 of the OCS annual oil and gas production and total annual bonus bid, royalty payments, and rentals. In concocting this table, we used a discount rate of 10%. Combining the three bottom-line figures leads to the upper line in Figure 3.1, which indicates the combinations of landed oil and gas prices the developers would have had to obtain in order to break even on their investment in bonus bids and royalties assuming a 10% cost of capital and making the overly pessimistic assumption that the pre-1972 leases stop

TABLE 3.1

PRESENT VALUE (1972) OF PUBLIC PAYMENTS AND OCS PRODUCTION THROUGH 1971

Year	Bonus, Royalty and Rent $\$ \times 10^6$	Price Inflator to 1972	Present Value Factor @ 10% to 1972	Present (1972) Value of Payments in 1972 Dollars $\$ \times 10^6$	Present Value (72) of Oil Production MM bbls	Present Value (72) of Gas Production MMM cf
1954	149	1.59	5.56	1,317	16.7	311.4
1955	118	1.58	5.05	941	30.3	409.0
1956	11	1.54	4.59	78	45.9	380.9
1957	14	1.47	4.18	86	62.7	346.9
1958	19	1.45	3.80	104	91.2	486.4
1959	117	1.42	3.45	573	117.3	714.1
1960	325	1.41	3.14	1,444	147.6	857.2
1961	48	1.38	2.85	189	173.3	906.3
1962	555	1.38	2.59	1,983	220.1	1,170.7
1963	99	1.36	2.36	318	231.3	1,331.0
1964	186	1.33	2.14	529	246.1	1,331.1
1965	101	1.31	1.95	252	265.2	1,260.0
1966	340	1.27	1.77	764	309.8	1,782.4
1967	655	1.23	1.61	1,297	333.7	1,911.1
1968	1,533	1.19	1.46	2,663	368.9	2,231.1
1969	336	1.13	1.33	505	392.3	2,598.8
1970	1,206	1.07	1.21	1,561	407.8	2,970.0
1971	419	1.02	1.10	470	429.0	3,054.7
TOTALS				15,074	3,888	24,010

Breakeven prices on bonus bids and royalties assuming no more production after 1971 are given by

$$P_{oil}\,[3.888 \times 10^9] + P_{gas}\,[24.010 \times 10^9] = 15.074 \times 10^9$$

Present value of 20 years of 1971 production is $3,646 \times 10^6$ bbls oil and 25,964 Tcf gas. Therefore, breakeven prices on bonus bids and royalties assuming 1971 production for 20 years is

$$P_{oil}\,[7.534 \times 10^9] + P_{gas}\,[49.974 \times 10^9] = 15.074 \times 10^9$$

producing in 1972. If one moves to the other extreme, and makes the overly optimistic assumption that the pre-1972 leases produce at their 1972 levels for twenty years, one obtains the lower line shown in Figure 3.1. Since gas was selling in the neighborhood of 15¢ to 20¢ per Mcf over this period, the developers would have had to obtain in the neighborhood of $1.25 to $1.50 per barrel for their production just to break even on their lease and royalty payments. Exercises with the MIT Offshore Development Model simulating the relatively small size of the Gulf fields, the extremely low allowables, and, by present-day standards, inefficient technology employed (many platforms with a low number of wells per platform) indicate that an average resource cost of landing this oil in the neighborhood of $1.50 to $1.75, as claimed by the industry, is not unreasonable. Prior to 1972, the landed value of this oil was in the neighborhood of $3.00 to $3.50 per barrel in 1972 dollars, indicating that offshore oil was roughly a break-even proposition as far as the industry was concerned and that the great bulk of the increase in national income associated with this oil (the difference between the landed values and the resource costs) was being transferred to the public in the form of lease and royalty payments. Other analyses of this issue based on figures up to 1972 by the U.S.G.S. (16), industry (17), and a number of independent observers (18, 19) have come to the same conclusions. It appears that effective competition was maintained among bidders at least through 1971.

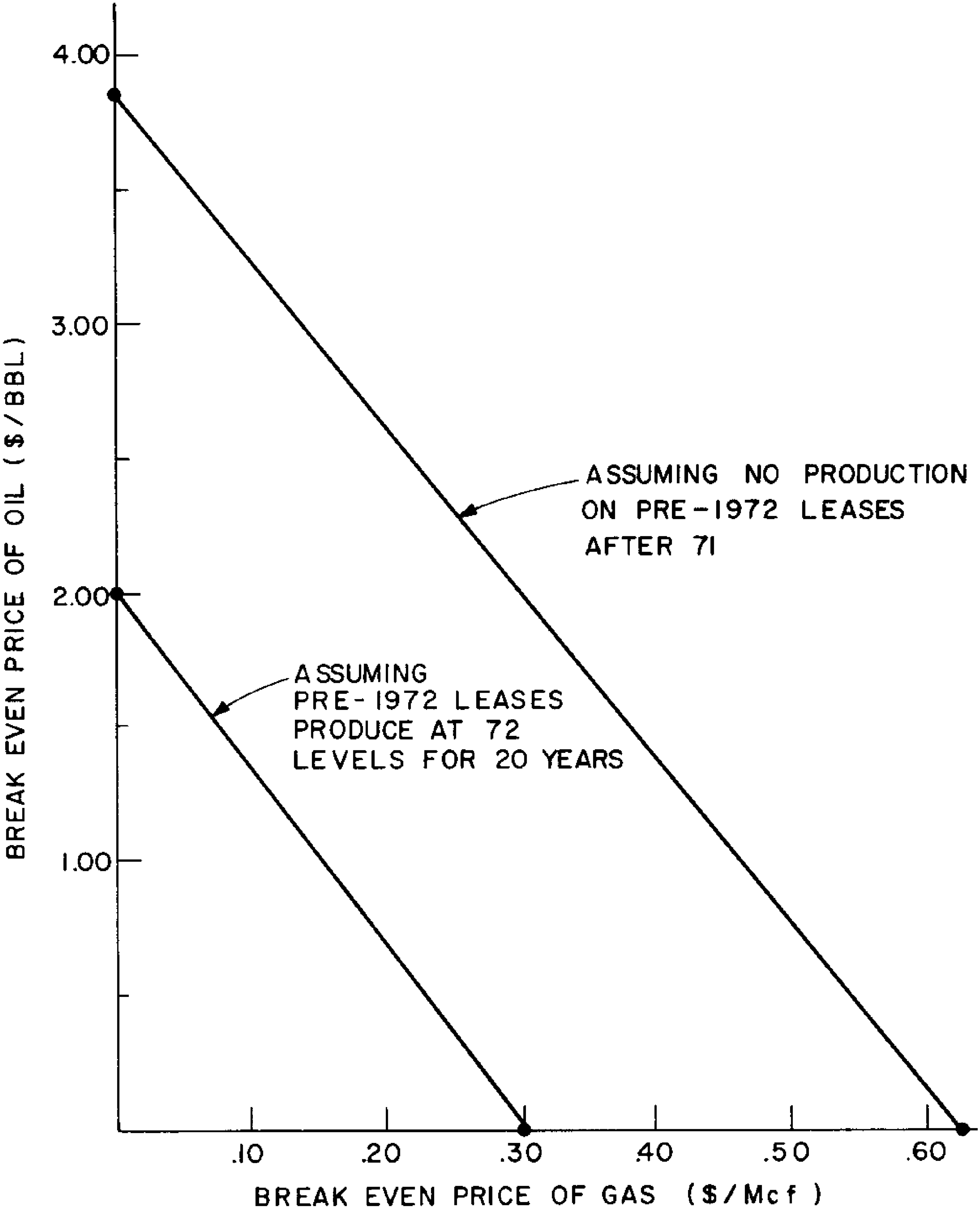

FIGURE 3.1 COMBINATIONS OF OIL & GAS PRICES ON OCS LEASES THROUGH 1971. REQUIRED TO BREAK EVE ON LEASE & ROYALTY PAYMENTS ONLY.

However, the 400% inflation in crude prices over the last two years may have changed the situation.* The abovementioned wide disparity between the cost of landing oil from a sizable (say 200 million barrel recoverable) find and the present value of that oil implies that for the top prospects, the competitive bonus bids should run into the hundreds of millions of dollars and more. If, on the Destin Dome, Exxon thought it had a 10% chance of finding 1000 million barrels recoverable, a 20% chance of finding 200 million barrels recoverable, a 20% chance of finding 100 million barrels recoverable, and a 50% chance of coming up dry, the competitive bonus bid would have been in the neighborhood of 750 million dollars.** This is an awful

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*The unanticipated price rise in itself has generated substantial in-the-ground inventory profits on oil bid on prior to the price rise. However, this fact cannot be pointed to as an indication of lack of competitiveness in the bidding, since the market could not have been expected to have foreseen the unprecedented and practically unopposed development of the OPEC bargaining position.

**The Destin Dome is about twenty miles offshore in about 250 feet of water in an area in which the design wave height is slightly less than fifty feet. The best prospects are thought to be in a pay, some 13,000 feet which tends to generate gas drive fields in neighboring Mississippi-Alabama. Inputting this set of variables to the Offshore Development Model and holding all the other variables fixed at the values shown on page 45 leads to a primary oil recovery of 24% and a unit oil cost of

Original Oil in Place (Millions of Barrels)	4.0	.8	.4
Primary Oil Recovered (Millions of Barrels)	1.0	.2	.1
Unit Resource Costs (Dollars)	.75	1.21	1.62

Assuming a 12-1/2 royalty, gas price at 50¢ per Mcf, and that the developer has no way of reducing his corporate lot of money to put up when one has a 50:50 chance of losing it all.

In order to pool such risks, it has become common practice for large oil companies to bid on tracts jointly. In the face of such risks, one can hardly blame even extremely large majors for joining together for the purpose of spreading the risks, nor their banks for insisting they do so. Nevertheless, the net effect of such bidding combines is to make it increasingly hard to argue that we have effective competition among lease bidders. The effect of

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income tax liability by joining this project with others which have negative taxable income, the present value pre-lease after-tax profits as computed by the model are:

Original Oil in Place (Billions of Barrels)	4.0	.8	.4	0
Pre-Lease Profits (Millions of Dollars)	5,000	1,000	350	-40

Assuming for the moment risk neutrality and applying the above hypothetical probabilities, the expected present value, pre-lease profit in millions of dollars is

$$.1(5,000) + .2(1,000) + .2(350) + .5(-40) = 750$$

The actual amount bid by Exxon and its partners on the eastern portion of the Destin Dome was about 590 million dollars.

The above computation is considerably complicated by the interaction between lease payments and corporate income taxes. Under U.S. tax law it is possible for a corporation in a capital-intensive business to pay substantial income taxes on a project which has zero net present value. This implies that a portion of the economic rent accrues to the public through corporate income taxes even if the developer bids away all or almost all his pre-lease net present value in the bonus bid. The MIT Offshore Development Model handles this interaction iteratively. The fact that a developer can pay taxes on a zero present value project may result in a nearly marginal field which should be developed from the point of view of national income, not being developed. We shall have cause to refer to this problem in the sequel.

the absence of such competition could be a transfer of tens of billions of dollars of real income from the public to the developer.

While we shall have to wait several years before we can really analyze the effective competitiveness of recent lease bidding, some characteristics of this bidding are worth some consideration. Over the period June 1973 through 1974, the federal government realized a total of 8.1 billion dollars from bonus bids on five major lease sales, all in the Gulf.*

Date	Bonus Accepted (Millions of Dollars)	Avg No of Bids Per Tract Bid
6/19/73	1,591	5.30
12/20/73	1,491	4.19
3/28/74	2,093	3.53
5/29/74	1,471	2.86
10/16/74	1,427	2.21

The decrease in bidders per tract bid despite the decrease in real amount risked may simply be due to a decrease in the interest in the prospects. It is true that the high-value tract tends to attract more bidders than the low. Nonetheless, any auctioneer would have to feel a little uncomfortable when on the average his offerings are attracting less than three bidders per piece. It is also true that the ratio of the value of the average bid to that of the high bid drops as the high bid increases, thus a goodly portion of the high-value tract bids assume the character of nuisance offerings.

*We are excluding the 7/30/74 lease sale of tracts formerly offered on which top bids were rejected as an atypical sale.

For example, on the Destin Dome tract which drew the record high OCS offering in December 1973, the following eight combines were bidders.

58% Exxon 25% Mobil 17% Champlin	$213,000,000
34% Chevron 33% Union 33% Amoco	111,000,000
100% Sun	46,000,000
25% Conoco 25% Phillips 25% Shell 25% others	33,000,000
Skelly & others	8,000,000
100% Arco	7,000,000
Allied & others	5,000,000
100% Murphy	500,000

It is difficult to regard any but the first two to four bids as serious offerings on the largest structure ever to be offered in the Gulf.

The two traditional requirements on competitive bidding are:

1. a sizable number of bidders; <u>and</u>
2. no prebid communication between bidders.

As we have seen, with the emergence of the bidding combine, the number of bidders has become uncomfortably small. With respect to lack of communication, we also have some problems. One certainly does not have to hypothesize attempts at collusion to explain the existence of bidding combines. Nonetheless, it is inherent in the formation of such combines and, just as importantly, in the negotiations which may or may not lead to the formation of a combine, that information be transferred between bidders on their evaluation of the various tracts.

The possibilities for such information transfer can be illustrated by studying the composition of the combines bidding on the March 28, 1974 sale. The pairs of large oil companies in Table 3.1 were linked directly in one or more combines, that is, they were members of the same combine. These are direct relationships. If one wishes to consider indirect relationships, it is possible to form a chain of bidding combine relationships in this single lease sale embracing nineteen of the twenty largest oil companies in the U.S. The exception is BP, which was not a bidder on this sale. Thus, the opportunities, or more precisely, the requirements for at least partial communication between bidders are numerous. This conclusion holds under the assumption of not only no overt attempt at collusion, but even of a concerted attempt to avoid such collusion. There is simply no way companies can intelligently choose between bidding partners unless considerable information flows between both actual and potential partners.

What effect the low number of bidders and the communication between bidders has had on the level of bids is impossible to say at this juncture. Nonetheless, given the foregoing, it would be only prudent on the part of the taxpayer to examine alternative leasing means. The major alternatives to the present system are:

- work obligation permits
- royalty bidding

TABLE 3.1

Companies Directly Linked	Number of Combines Link Occurred In
Amoco-Burmah	1
Amoco-Mobil	11
Amoco-Occidental	1
Amoco-Shell	4
Amoco-Union	2
Arco-Cities	10
Arco-Conoco	8
Arco-Getty	7
Burmah-Occidental	1
Burmah-Mobil	6
Chevron-Gulf	5
Chevron-Mobil	5
Chevron-Tenneco	2
Chevron-Union	37
Cities-Conoco	14
Cities-Getty	11
Cities-Sun	1
Conoco-Getty	11
Conoco-Shell	5
Exxon-Mobil	1
Gulf-Mobil	13
Gulf-Tenneco	5
Gulf-Texaco	9
Hess-Marathon	20
Mobil-Tenneco	4
Mobil-Texaco	4
Occidental-Tenneco	1
Tenneco-Texaco	18

- high fixed royalty plus bonus bid
- bid on percentage of net revenues
- public exploratory drilling plus bonus bid

CHAPTER 4

WORK OBLIGATION PERMITTING

Work obligation permitting has several variants. But basically it involves potential developers submitting their exploratory drilling and provisional production plans for a particular tract and the government choosing that developer with the most aggressive, best considered plan. Usually such a scheme is combined with fixed royalties and/or fixed lease rentals, generally set at nominal levels. Both the Norwegians and the British began with variations of work obligation permitting in the North Sea.

Under this system, the great bulk of any economic rent is transferred to the developer. A portion of this rent will than be returned to the public in the form of corporate income taxes. Of all the possible methods which we will review, this is clearly the most favorable to developer income.

Theoretically, this method could be administered in such a manner as to result in maximum national income but this will be dependent on the skills and honesty of the administrating officials. There will be a temptation for prospective developers to present work plans which represent overdevelopment of the resource in order to be judged the most aggressive to, for example, promise to place more than the national income maximizing number of platforms on the field decreasing the net present value obtainable from the resource. The administrators will have to be sharp enough to recognize such overdevelopment and refuse it. In order to select the "best" work plan, one has to be able to figure out what the best plan is. If the government agency can actually do this, then there exist a number of other alternative management policies which also result in maximum national income but, at the same time, avoid any transfer of the economic rent to the developer.

Perhaps more importantly, given the potential value of the best and hence most important prospects and the necessarily judgmental decisions which will have to be made in choosing the "best" work plan, this method is an open invitation to corruption.* Given the possibility of incompetence or corruption, the possibility of the choice of inefficient developers exists which could result in a loss in national income.

However, the basic rap against work obligation permitting is not the loss in national income but the large-scale transfer of income from the public to the developer. From a non-developer income point of view, the alternative is clearly counterindicated. If the expected economic rent associated with a prospect is near zero,

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*This corruption may not take illegal forms. Such devices as the post-government job are much more likely.

any of the competitive bidding schemes will reveal this fact by resulting in a near-zero high bid,* in which case the development will proceed much as if an efficient, non-corrupt, work obligation permit plan were in effect.

As soon as it became clear that there was economic rent associated with North Sea oil, Norway and to a certain extent Britain moved away from work obligation permitting. It became obvious, at least to the Norwegians, that continuance of work permitting would result in a large-scale transfer of income away from Norwegians to foreign developers.

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*Provided effective competition is maintained among bidders. In the absence of such competition a near-zero top bid does not necessarily imply an expected near-zero economic rent.

CHAPTER 5

ROYALTY BIDDING

Royalty bidding involves competitive bidding on the share of the actual gross revenues associated with the resources. Generally, this is done on a percentage of market value. Royalty bidding has had a long history in the United States in state sales and was experimented with by the federal government in the October 1974 Gulf of Mexico lease sale in which ten tracts were offered on a royalty bid basis.

As compared with bonus bidding, royalty bidding involves a transfer of a portion of the risk associated with the uncertainty existing prior to exploratory drilling from the developer to the public. This has an advantage in maintaining competition among bidders. Under royalty bidding it is not necessary to risk large amounts of capital up front as in bonus bidding, and thus the argument for bidding combines disappears. If royalty bidding became the standard method, presumably bidding combines would be outlawed. The barrier to entry presented by the requirement of a large up-front bonus bid in the face of uncertainty would be removed.

The basic problem associated with royalty bidding can be illustrated by the following argument. Assume for the moment the objective of the OCS management system is maximum public income subject to the constraint that the size of the national pie not be diminished. That is, assume our management system has the twin goals of:

1. Maximum national income--that is, all resources whose development would increase national income should be produced, and that oil should be produced by the least resource cost means available.

2. Given (1), the economic rent associated with this production should accrue to the public; that is, <u>on the average</u> the developers should earn little more on their investment in offshore oil than they would have earned on alternate investment elsewhere.

Theoretically, competitive royalty bidding could accomplish (2), but it will have great difficulty accomplishing (1). The reason is that the royalty bid, unlike the bonus bid, affects the developer's <u>marginal</u> expenses. Consider a site 75 miles offshore, in water 300 feet deep, with a design wave height of 100 feet, in which the bidder feels there is a 20% chance of finding 500 million barrels of reserves, a 20% chance of finding 250 million barrels, a 20% chance of finding 125 million barrels, and a 20% chance of finding 62 million barrels. Assume further our bidder is willing to assume that the other reservoir parameters are those given on page 45. Then assuming an $11.00 landed price of oil and effective competition among bidders, and referring to Table 2.3, the royalty bid would be in the neighborhood of $7.00 per barrel, or 66%. Now suppose exploratory drilling reveals that the tract actually contains 100 million barrels of oil in place. According to Table 2.3, the cost to the country of developing and landing that oil is $5.65, much cheaper than the cost to the country of OPEC crude, say $11.00 per barrel landed. In this situation, U.S. national income will be increased by $11.00 - $5.65, or $5.35, for every barrel of oil landed from this find.

However, the cost to the developer is the resource cost, $5.35, plus the royalty, $7.00, for a total of $12.35. The developer will lost $1.35 for every barrel he lands, and in this situation will not land the oil, with a loss in national income of some 150 million dollars. The problem is that the royalty bid, if successful, will set up a large disparity between the cost to the nation and the cost to the developer, leading the developer to make real national income reducing decisions.

The foregoing argument applies to primary oil. It holds a fortiori for secondary and tertiary production which in general will have a marginal cost higher than primary oil, yet still may cost the nation considerably less than foreign crude. Aggregated over all potential finds, the loss in national income could easily run in the billions of dollars.

Proponents of royalty bidding are aware of this problem and offer two possible outs: releasing and renegotiation.

1. Releasing involves a policy in which as soon a developer decides not to produce or no longer to produce a tract, he must turn it back to the government with all the equipment intact, whereupon the government releases the tract at a (presumably) lower royalty. With some administrative problems, this would meet the objection as far as primary production is concerned, but problems with respect to enhanced recovery remain. The original leaseholder may choose to just take out the flush production over a sizable period, twenty years, rather than make the additional investment to bring additional oil out in this period. Even assuming he turns the depleted field back in twenty years and it is released for secondary and tertiary recovery, the nation will have lost in present value terms and very likely in ultimate recovery as well, for often secondary and tertiary recovery methods are more effective and/or less costly if they are initiated early in the producing life of a field. Also, due to the increasing marginal cost inherent in producing additional oil, we might see many rounds of releasing in a field with consequent transfer and administration costs.
2. Renegotiation involves a policy where if a developer feels he cannot develop a field at

his bid royalty, he presents evidence to this effect to the regulatory body, which is empowered to grant him a decrease in royalty. This involves a number of problems. First, there are the problems associated with verifying the developer's expenses. Typical accounting methods will not work. In offshore petroleum, which is an extremely capital-intensive business, the cost of capital is the single largest expense. Present value techniques will have to be used and the choice of a cost of capital will be critical. Still more basically, the developer in the renegotiation process will realize he will have to pay some royalty and will attempt to present and "sell" that royalty which will maximize his net present values post this royalty, which in general will not be the national income maximizing development. Further, given the increasing marginal resource cost associated with enhanced recovery, we may be faced with a whole series of renegotiations as the field becomes depleted. Lastly, the invitation to "gold plating" is obvious, since any additional expenses entailed will come off the developer's royalty. Finally, there is the problem of the 110% royalty bid, i.e., an artificially high bid which assures the bidder the tract under unprofitable terms, whereupon he renegotiates. All in all, a messy can of worms.

The terms of experimental royalty bidding in the Gulf of Mexico explicitly recognize the possibilities for renegotiation, but no mention is made of releasing. Some of the results of this royalty bidding are shown in Table 5.1 . The absence of the majors among the top bidders and among bidders in general is conspicuous. There are a dozen possible specific reasons for this absence, but it would seem that the majors feel their capital would be more profitably invested in bonus bids. A small point to be sure, but one that certainly doesn't argue for effective competition in bonus bidding.

The problems associated with administering a royalty bidding system have led some to suggest a compromise between royalty bidding and bonus bidding. This temporizing policy would involve

- a "high" fixed royalty, say 40% of landed value
- bonus bidding as at present.

The argument is that the shift of the economic rent to the royalty would decrease the competitive bonus bids and hence mitigate the need for bidding combines which in turn would alleviate the problem of maintaining competition among bidders. This is true. Unfortunately, this alternative faces the same basic problem as straight royalty bidding. The royalty, whether it be a bid or fixed, is an increment

TABLE 5.1

ROYALTY BIDS ON SEVEN GULF OF MEXICO TRACTS OFFERED OCT. 1974
(BIDS BELOW 12% MINIMUM NOT SHOWN)

36025		36042		36080		36103	
Oil and Gas Futures	73%	American Petrofina	65%	American Petrofina	67%	Huskly	73%
CNG & Koch	59%	Oil and Gas Futures	60%	Oil and Gas Futures	53%	Oil and Gas Futures	63%
Ashland & others	56%	Columbia Gas	50%	Allied Chemical	51%	Exchange	53%
Texas Int. & others	55%	Terra	27%	Mesa & others	31%	Texas Int. & others	48%
Mesa & others	45%					Mesa & others	36%
Felmont & Case	41%					Oil and Gas Futures	36%
Huskly	39%					La. Land & others	35%
Louisiana Land	35%					Texas Pac.	32%
Mobil & others	34%						
Sun	28%						

36145		36210		36292	
Texas Int. & Basin	78%	American Petrofina	71%	American Petrofina	52%
C&K	71%	Offshore & others	43%	Placid & Man.	50%
American Petrofina	67%	Mesa & Others	26%	Chevron	27%
Huskly	56%	Skelly	25%	Exxon	20%
Belco	53%				
Lone Star	50%				
Mesa	48%				
Superior & others	46%				
Terra & R&B	45%				
CNG	38%				
Chevron	38%				
Sun	26%				
Exxon	20%				

to marginal cost and hence, unless renegotiated, will prevent some oil which should be landed from a point of view of national income from being landed.

Another compromise between royalty bidding and bonus bidding which has been suggested is installment bonus bidding. Under this alternative, a developer would bid a fixed amount as in bonus bidding. This amount would be paid in three installments (immediately, after three years, and after five years in one variation). The important difference between installment bidding and bonus bidding, however, is that the lessee would have the right of surrender of the lease before the second and third payments. This provision makes the system closer to royalty bidding than bonus bidding and poses the same problems from the point of view of national income. If a developer originally bid 600 million dollars total for a lease and after exploratory drilling found the net present value of the development on a resource cost basis was, say, 350 million, then he would abandon the tract rather than pay the final 400 million dollars, despite the fact that national income would be increased by 350 million dollars if the find were developed.

Installment bidding does have two significant advantages over royalty bidding:

a. There is an automatic releasing provision. Presumably in the above case, as long as the original developer was required to make all exploratory drilling information public, the tract could be released.

b. On those tracts that are not abandoned, the cost of the marginal unit of oil is not affected by the payments, so enhanced recovery investments would be the same as in the bonus bid case.

Finally, it is not clear that installment bidding really faces up to the problems of maintaining competition among bidders, although it may ameliorate them. The first payments of competitive installments are likely to remain quite large, forcing all but a limited number of combines out of the game. There are two reasons for this.

1. One-third of the expected present valued economic rent on really top prospects--the important ones--can still run several hundred million dollars.

2. The developers know they have the option of not paying any but the first payment, and under competition this would increase the present bid value under installment over that under bidding straight bonus. Suppose the Destin Dome is to be leased with the resource costs and probabilities of page 74 applied. Then let B be the present value of the amount bid. Under bonus bidding, the risk-neutral developer would be willing to pay up to B where

$$.1(5000 - B) + .2(1000 - B) + .2(350 - B) + .5(-40 - B) = 0 .$$

Under three-payment installment bidding where only the first payment has to be made before exploratory drilling, the maximum present value bid would be given by

$$.1(5000 - B) + .2(1000 - B) + .2(350 - 1/3\ B) + .5(-40 - 1/3\ B) = 0 .$$

For fields of 400 million barrels in place or less he will surrender the lease rather than make the second and third payments. Obviously B will be larger under installment bidding than under bonus bidding. One-third of the competitive installment bid may be considerably larger than one-third of the bonus bid.

In summary, installment bidding is a compromise between bonus bidding and royalty bidding. As such, it has some of the problems of both. Like royalty bidding, it can lead to national income decreasing decisions, but in this case, the releasing alternative occurs in an explicit and natural way. Unfortunately, given the extremely high expected value of the best prospects, it is probably also liable to the same criticism as bonus bidding. The up-front payments made under great uncertainty, while not as large as those under bonus bidding, may still be large enough to substantially restrict competition among bidders.

CHAPTER 6

PERCENTAGE OF EXCESS PROFIT BIDDING

A considerably more attractive option than royalty bidding is percentage of profit bidding. This has never been used in U.S. petroleum leasing, but it is a feature of several recent Senate bills and, for all practical purposes, is the basis of the Norwegian system and the emerging British system.* Properly administered, this system will not affect the developers' development decisions, for the alternative which maximizes the net present value of the resource before profit-sharing (the real national income maximizing alternative) will also be the alternative which maximizes after-profit-sharing profits. Unlike royalty bidding, this alternative does not tax the marginal unit of oil. If the landed price is $11.00 per barrel, the developer will land any oil whose resource cost is less than $11.00 including that oil which costs $10.99, for on that unit, he will pay the government only the bid percentage of the differential between the market price and the resource cost.

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*The Norwegian system actually involves the bidders bidding on share of government participation in the development of the tract. The government may or may not exercise its option to this share until after it has seen the results of exploratory drilling. Although some public moneys are invested in development of production facilities, the overall effect is very like net profit bidding.

Excess profit bidding has another nice characteristic. Provided excess profits are properly defined to be the <u>net present value</u> of the difference between revenues from the tract and the <u>necessary</u> outlays associated with the tract's development, and the present values are computed at an interest rate which is a reasonable estimate of the industry's cost of capital, then it is quite easy to say what the competitive bid will be. It will be 100% net present value less the present value of exploratory drilling expenses. Since the exploratory drilling expenses can be estimated with some degree of accuracy prior to exploratory drilling, excess profit bidding offers the public a reasonably reliable indicator of whether or not there is effective competition in the bidding; all in all, a rather attractive option and one worthy of serious consideration. It is clearly far superior to royalty bidding from the point of view of national income.

The problems associated with excess profits bidding are administrative. First, it is essential in this very capital-intensive business that the definition of excess profits be the net present value of the undertaking at a reasonably accurate estimate of the cost of capital, that is, excess profits must be defined by the relevant legislation to be equal to economic rent. This is an entirely different concept from the usual definition of taxable income. This difference will put a rather severe strain on current government and company accounting procedures.* Secondly, one must use a reasonable estimate of the cost of capital in discounting future revenues and expenses. The cost of capital will change throughout the life of the project and methods for reacting to or ignoring the changes will have to be decided on. Thirdly, it will be necessary to maintain rather tight supervision to ensure that only <u>necessary</u> expenses are incurred, for if, for example, the bid is 90% of excess profits, the company will pay only 10% of any unnecessary expenses, while the taxpayer will pay the rest, with obvious pressures for goldplating, kickbacks, overcompensating executives, etc.

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*For example, current legislative proposals define profits in the usual IRS sense. This could very well result in national income maximizing developments not taking place for the reasons outlined on page 74.

CHAPTER 7

PUBLIC EXPLORATORY DRILLING FOLLOWED BY FIXED BONUS BIDDING

In a world without uncertainty, the bonus bid system would have much to recommend it, and in fact would be the almost automatic choice as the preferred alternative if one's goals are maximum public income subject to maximum national income. From the point of view of the developer's exploration and production decisions, the bonus bid is a sunk cost and will have no effect on his development decisions.* Any petroleum whose resource cost is less than the landed price will be produced. There is no need to monitor the developer's expenditures, for he pays 100% of any unnecessary expenses. The organization which can pay the largest bonus bid is by nature an efficient developer. If there were no uncertainty, we would have no qualms about applying antitrust strictly, making bidding combines illegal and prebid information transfer subject to heavy penalties. In this situation it is quite likely that effective competition could be maintained. In terms of corporate structure, the oil industry is considerably less concentrated than perhaps any of the primary commodities industries with the exception of agriculture.

*Due to the unfortunate manner in which our tax laws define profits, this is not quite true. If a lessee abandons a lease, he can expense the entire bonus bid. If he produces the lease, the bid must be capitalized over the life of the field. The difference in present valued tax benefits is not sunk at the time the production decision is made and may induce the developer to abandon certain marginally sized fields with a loss in national income.

The industry argument that large bonus bids in themselves slow development is specious. Assuming for the moment no uncertainty, any investment which has a positive net present value at the market cost of capital will attract capital from the capital market. The industry had no problem securing five billion dollars for a single investment, the Trans-Alaska pipeline, or one billion dollars to develop a single field in the North Sea. Investments which are profitable at going interest rates will attract capital and if an investment is not profitable at the going interest rate, it is the market's way of saying that society has other things to do with its capital which are more valuable and the subject investment should be deferred.

The fact that offshore developers are falling over themselves in a scramble to obtain rigs, platforms, tubular goods, etc. and that they are constantly lobbying for more leasing is prima facie evidence that the bonus bid has not held up offshore development. The problem is not that the bonus bids are too high! The problem from the point of view of the taxpayer is that when one combines bonus bidding with very significant uncertainties, the bonus bids may be too low.

If the basic problem with bonus bidding, then, is uncertainty, the obvious alternative is to go after this uncertainty directly. This is the rationale underlying public exploratory drilling.

Offshore petroleum exploration and development consists of three quite distinct stages:

1. Geophysical exploration
2. Exploratory drilling
3. Erection of production and transport facilities and production drilling.

Geophysical exploration consists of magnetic, gravity, and, primarily, seismic surveys. At present in the U.S., this is funded by private companies, usually in combinations known as group shoots which may include as many as twenty companies. Often the U.S.G.S. buys a share in such syndicates, obtaining access to the data under the stipulation that it not be divulged outside the U.S.G.S. The output of the geophysical survey is the location, magnitude, size, and character of structural traps, which may or may not contain petroleum. These are the drilling prospects. In some cases, the amplitude of the seismic reflection can be used as an imperfect indication of the presence of gas, which increases the likelihood that a particular structure actually contains petroleum. However, even under favorable circumstances, after geophysical exploration very significant uncertainties exist as to the existence of any oil in the prospect and certainly the magnitude of such oil.

The second step, exploratory drilling, involves drilling the prospect from a mobile drilling rig. Sometimes one or two wells are sufficient to determine that commercial quantities of oil do not exist in the structure, although in some unusual cases it may be prudent to invest in four or five wells before writing a structure off.* If the first well indicates commercial quantities of petroleum, then it will generally take half-a-dozen additional wells to completely delineate the find, although often the information from the discovery oil, combined with geophysical data, is sufficient to give one a rather good idea about just what's there.

Assuming commercial quantities of petroleum are discovered, the third step involves the construction of permanent production platforms, the erection of these platforms on the discovery, and the drilling of from ten to forty wells from each platform into the reservoir. At the same time, transportation facilities in the form of pipelines or tanker loading facilities are constructed and put in place.

Under the present U.S. management system, lease bidding takes place between steps 1 and 2, at which point very great uncertainty can exist with respect to what's there. Under public exploratory drilling, the public would fund and bear the risk of both geophysical surveying and exploratory drilling, after which bonus bidding would take place. Prior to this bidding, the government

*As noted earlier, the complex structures found in the vicinity of salt domes may require twice this many exploratory wells.

would make available to prospective bidders all the information obtained, including raw data and any analyses and interpretations which the government had commissioned or made. At this point, the uncertainties with respect to the amount and form of petroleum in each tract, including oil and gas characteristics and basic reservoir parameters, would be very much less than before the tract is drilled. The problem essentially becomes one of bidding under certainty. Antitrust could be enforced strictly, combines made illegal. Any knowledgeable observer could compute the approximate value of the tract, and if bidding were not at competitive levels, that fact would be apparent to all. Operators without large capital bases could take the results of exploratory drilling to banks and financial institutions and make a strong case that financing a bid at, say, 80% of the computed economic rent of the site would be a very low-risk investment. They could mortgage the petroleum in the ground, much as coal companies do presently. Large oil companies would know that the independents could do this and would be forced to maintain their bids at close to zero excess profit levels. Public exploratory drilling regains us all the nice properties of bonus bidding while avoiding the breakdown of bonus bidding in the face of very high expected value tracts combined with great uncertainty.

The major objection to public exploratory drilling is summed up in the statement by one oil company executive, "A government that can't run a post office can't run an exploratory drilling program." Indeed, given our experience with many governmental programs, the issue bears investigation. However, the analogy may be an unfair one. For the most part, oil companies do not do their own geophysical surveys nor exploratory drilling. The work is contracted out to a range of specialized service industries. The oil companies serve primarily as a financing vehicle and outlet for resulting production. Oil company employees are very much in the minority offshore. Any given rig or manned platform may have thirty to sixty people aboard. Rarely are more than two or three of these people employees of the lessee, and even these people perform primarily a monitoring function. Large oil companies do perform considerable in-house evaluation of both geophysical and exploratory drilling data obtained by their subcontractors, although there are independent software houses and laboratories who offer these services commercially.

Presumably the same service companies would be available to the government, which would contract out for this work. Since the whole idea is to make all the data and results public, there is no need to be concerned about information security, which is one of the major reasons why the larger oil companies elect to do their final evaluation in house. Unlike the post office, the geophysical and exploratory drilling program would not be accomplished by government employees, but contracted out on a competitive basis, rather like defense contracts, with much the same administrative problems. A better analogy would be the statement, "A government which can (cannot) run an airforce can (cannot) run an exploratory drilling program." Insert predicate of your choice.

What hints can we obtain as to the ability of a government exploratory program to find oil relative to the ability of industry? First, there is the abovementioned fact that many of the same talents presently evaluating prospects for the private companies will be available to the government. Contractor services directly, and certainly some industry personnel will transfer to government when they find their jobs have moved.

Secondly, there is the nature of oil in the ground itself. The size of oil fields ranges from the tens of billions of barrels to less than a million barrels, over five orders of magnitude. As a result, aggregate volume of recoverable reserves are dominated by a very few, very large fields. Of the 60,000 producing fields in the United States, 300 account for over 65% of the present estimates of domestic recoverable reserves. Eleven fields account for over 45% of total recoverable reserves, and one field close to 25%. In other words, when all is said and done with respect to finding oil, it's the very few, very large fields that count.

In general, the large fields are the easiest to find: the volume-weighted average year of discovery of the 300 largest domestic fields is 1934, a time when gravimetry was in its infancy and seismic survey rarely used. In short, on a national basis, the success of our exploration program depends on its ability to find large fields, and for the most part, large fields are in obvious structures which will be identified as prospects by any reasonably competent body. The hard-to-locate fields, where the difference between a reasonably competent and extremely competent exploration program is critical, by their nature tend to be the marginally-sized fields. How quickly prospects tend to fall off is demonstrated by the fact that despite intensive efforts over the last twenty years, using vastly improved geophysical technology, the industry has been able to find only four fields with recoverable reserves in excess of one hundred million barrels on land in the Lower 48.

Both the above arguments suggest that a government-run exploratory program would be about as effective as a privately-managed program. What little empirical evidence we have is less reassuring. Several authors have commented on BLM's inability to predict the results of their lease sales. BLM generates pre-sale estimates of each of its tracts. The major purpose of this estimation is to generate cut-off levels. If the high bid is below this cut-off level, it will not be accepted. Post-mortem comparison of the pre-sale estimates with actual high bids by tract indicate:

a. In aggregate, the government's pre-sale estimates are much lower than the actual high bids, usually by a factor of three or more.

b. On individual tracts, there are generally wide discrepancies in both directions between the high bid and the pre-sale estimate, often varying by a factor of ten or more.

The downward bias of the pre-sale estimates can perhaps be explained by the fact that they are essentially minimum acceptable bids, and given BLM's view of its mission to generate offshore production, we would expect these minimums to be quite conservative.* One's best guess of the value of a prospect and the minimum bid one would accept if forced to are two quite different concepts.

More worrisome is BLM's inability to pick out the individual tracts judged most valuable by industry. In the October sale, only three of the ten tracts experiencing the top bids were also in the top ten of the pre-sale estimates. The top bid tract went for 118 million dollars; the pre-sale estimate was six million dollars. The second highest tract went for seventy-nine million; the pre-sale estimate was seventy-two thousand. It is generally true that the tracts which rank high on the government's list receive substantial bids, but the converse is not true. Many of the tracts which the industry ranks high are not ranked high in the pre-sale estimates. The bids (pre-sale estimates) and relative ranking of the twenty top bid tracts of the March 1974 sale are shown in Table 7.1.

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*Not to mention the flack BLM takes from the industry whenever it rejects a substantial bid.

TABLE 7.1

COMPARISON OF LEASE BIDS AND PRE-SALE ESTIMATES
TOP TWENTY TRACTS, MARCH 28, 1974 SALE

Tract	High Bid ($ Millions)	Bid Ranking	Pre-Sale Estimate ($ Millions)	Estimate Ranking
158	169	1	9	23
209	113	2	.1	100
214	81	3	29	6
125	79	4	4	41
64	76	5	6	39
137	72	6	33	3
126	72	7	9	22
153	66	8	4	47
215	64	9	.1	100+
99	64	10	19	11
40	58	11	3	54
36	53	12	4	52
147	46	13	17	12
68	45	14	.5	79
157	42	15	37	2
124	41	16	3	58
37	39	17	1	74
142	38	18	24	8
210	38	19	.1	100+
4	37	20	32	4

There is nothing of comfort in this data for those who would argue that a government-run program, at least without substantial changes in the government's procedures, would look rather like the privately managed program. These results are typical of recent lease bidding.

In defense of BLM, it should be pointed out that the Gulf of Mexico is a rather unusual area geographically, with a tendency to have a large number of rather small structures rather than a few massive ones more typical of, say, the North Sea. The Gulf is probably an unusually difficult area in which to distinguish the truly top prospects from second-rate prospects. This is evidenced by the disparity in the individual bids on these tracts by the industry. Industry bids on tract 158 in the sale shown ranged from 169 million to thirty-three million dollars, and on tract 209 from 113 million to three million.

Also, under the present system, there is no real pressure to carefully evaluate the various prospects, for the BLM, with the exception of the minimum level cut-off, is serving in a passive monitoring role. The situation might be quite different if the agency were risking its own money. Nonetheless, it is obvious that some major changes will have to be made in Interior's leasing evaluation procedures if public exploratory drilling is undertaken.

The other basic argument against public exploratory drilling is essentially an ideological one, a feeling that

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The other basic argument against public exploratory drilling is essentially an ideological one, a feeling that government is not and should not be in the business of risking elderly widows' pensions in the offshore oil game. The amount of money which would be risked by taxpayers under this proposal would be roughly one billion dollars a year. In 1974 the industry drilled about 540 offshore exploratory wells, using sixty active mobile rigs. That is, exploratory drilling rigs can average about eight to ten wells per year aggregated over a variety of environments, well depths, etc. Total operation costs of a reasonably large, deepwater rig will run about $50,000 per day; thus exploratory wells average perhaps 2.0 million dollars apiece, although the range can be large, from less than five hundred thousand for a relatively shallow well in mild conditions requiring a short rig move to over five million for a difficult well in severe conditions. Thus, in order to maintain present industry exploratory drilling activity, a public investment in the neighborhood of one billion dollars per year would be required.

The cost of marine geophysical will be an order of magnitude less than this. The most recent data available is that for 1973. In that year the industry ran 260,000 miles of seismic survey on the U.S. continental shelf at an average acquisition cost of $213 per mile for a total expenditure of $55,146,000. The Society of Exploration Geophysicists estimates that the cost of data processing and assessment is about equal to the data acquisition expenses, for a total U.S. marine resource cost in 1973 of about 110 million dollars. Total expenditures throughout the United States for gravity and magnetic survey were less than two million dollars. This type of work will not represent a significant portion of the outlays of a public exploratory program.

Let us assume for the sake of argument that complete usurpation by the government of the exploratory function would involve a public investment of 1.5 billion dollars per year. Last year the government obtained a total of about five billion dollars in lease bonus bids, despite the fact that the government did not lease any frontier areas. Thus, for the taxpayer to break even would have required a 30% increase in bonus bids. Would this have happened?

There are two reasons for believing it would.

1. The bidders would be relieved of exploratory drilling costs and thus effective competition would force the bids up by the amount that the bidders would have had to spend on exploratory drilling, by the amount that they have saved. At present, the finding costs of OCS oil are averaging about fifty cents per barrel, or approximately one quarter the total <u>resource</u> cost of landing OCS oil. Thus, in very rough terms, competitive bidding will force the bids upward about fifty cents per barrel.

   This transfer of exploratory drilling costs to the bonus bids follows from the fact that from the point of view of the nation as a whole, it makes no difference whether the industry or the government contracts the exploratory program.* In both cases approximately the same resources (people, rigs, vessels, computers) will be employed with approximately the same opportunity cost in national income. As long as the government-funded exploratory program is approximately as effective as industry's, from the point of view of national income, the change in contractee is a wash.

The argument often heard, that public exploratory drilling is infeasible as a practical matter since there are not sufficient rigs, people etc. to do both the government program and private programs, is nonsensical. No one is talking about doing both. It's an either/or proposition. It would be pointless for a successful bidder to redrill exploratory holes on the site he has bid on on the basis of the results of the government exploratory program.

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*While we have this in mind, it is interesting to consider the Halbouty plan, a varient on bonus bidding in which a portion of the bonus would not be paid to the government but rather would be an obligation on the bidder to spend that amount on exploration and development. Under competition, the only effect of this system would be to increase the bonus bid an amount equivalent to the obligation which would have been spent anyway. This is essentially the present system. It has the disadvantage that, if initial exploration is extremely disappointing and the developer would ordinarily abandon the lease and cut his (and the nation's) losses, under this plan he will make further uneconomical investments in development since the marginal cost to him (but not the nation) is zero.

2. The above argument holds even if effective competition has been maintained among bidders under the present system. It depends only on the government-conducted drilling being approximately as effective as industry-conducted. If effective competition has <u>not</u> been maintained among lease bidders and effective competition is enforced in post-exploratory drilling bidding, then the increase in bonus bids will be greater than the cost of exploratory drilling. For example, if one feels that the total 1974 bids of about five billion dollars was 80% of the competitive bid levels, then the increase in bids under well-managed public exploratory drilling plus properly enforced competition would have been about one billion dollars in excess of the costs of the exploratory drilling. In essence, public exploratory drilling is an insurance policy against lack of effective competition in present bidding. As long as the exploratory program is reasonably well managed, the situation vis-à-vis the present is at worst a wash and if competition has not been maintained, will transfer excess profits from the developer to the taxpayer.

The industry position against public exploratory drilling in itself bears some investigation. It is a rare case of industry refusing public funding of its own research, especially research aimed at sharply decreasing uncertainties otherwise inherent in the investment. How many industries have clamored for public research funds on the grounds the investments are too great for the individual company? From the industry point of view, if the public exploratory drilling program turns out to be a boondoggle, as some industry spokesmen predict, the industry will have lost nothing and gained some free information. If present bids in aggregate are at zero excess profit levels, as industry likes to claim, and the program is not a boondoggle, then industry will have lost nothing while transferring the bulk of the risk inherent in any individual investment in the offshore oil industry to the taxpayer. The only situation in which public exploratory drilling would be against industry's interests is if the program would be effective and present bids are not in aggregate up to zero excess profit levels. Yet every industry spokesman of whom I am aware who has commented on the matter has come out strongly against public exploratory drilling.

The ideological argument against risking public funds in an endeavor as uncertain as exploratory drilling cannot withstand scrutiny at the theoretical level. A group as a whole can afford to be less risk-averse than any individual within that group. This phenomenon, based on the law of large numbers, is the raison d'être for the insurance industry. By collecting a large number of risks, one can assure with high probability that the actual aggregate extreme will be close to the average extreme. This, of course, is why the bidders have formed into combines, so that each bidder can obtain a share of a sizable number of risks, allowing him to be fairly confident that overall he will obtain something close to the expected outcome.

The nation contains no collective larger than itself. The nation as a whole can and does take risks that no individual, or even the collective of individuals represented by a large corporation, can undertake. Investment in the breeder reactor is one example. Insofar as the country can properly afford to act very much as an expected value decisionmaker (a risk-neutral investor) on any individual offshore lease tract while an individual corporation or combine of corporations must be risk-averse, the country as a whole is unnecessarily awarding the risk premium to the bidder, even assuming effective competition among bidders. In short, there is no theoretical basis for the feeling that the country as a whole should not incur risks which an individual company or group of companies is willing to incur. In fact, insofar as the bidders are risk-averse, there is a theoretical argument in the law of large numbers for just the opposite position.*

Another possible argument against public exploratory drilling is inefficiencies caused by the lack of continuity between the exploration phase and production phase. Certainly there will be an additional delay between

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*It is interesting that the same people who argue against public exploratory drilling on ideological grounds often also argue for royalty bidding, which involves a transfer of a portion of the risk inherent in OCS development to the public.

discovery of the field and actual production due to interruption for bidding. Also, all the exploratory wells will have to be expendable. (An expendable is a well drilled for information purposes only with no intention of producing the wells.) Often industry completes successful exploratory wells for subsequent production. Any economies obtained by so doing will be lost under public exploratory drilling.

However, the national cost of these inefficiencies may be rather marginal. The delay for bidding need be no more than three months representing a loss in present value to the nation at current cost of capital of 1% or 2% the net value of the find. The expendable versus completed well economics are so marginal that the industry regularly goes either way. Industry sources indicate that an exploratory rig which drilled only expendable wells could drill as many as sixteen wells per year in the Gulf, as compared to the actual average of eight or ten (15). Thus, drilling only expendable wells would decrease the amount of money the public would have to put up front by perhaps as much as 30% or 40%, with, however, an equivalent or slightly greater decrease in the subsequent lease bid.

In short, the diseconomies associated with having two different operators conducting the exploratory versus production drilling are far from overwhelming. And this interruption may result in one rather positive economy. Several industry sources, including the National Petroleum

Council, have commented on the inefficiencies associated with exploration of rectangular tracts whose boundaries have no relationship to the underlying structure. Often in the Gulf and elsewhere, a large structure will underly more than one tract. For example, about one-third of the Destin Anticline was put up for bid in December of 1973. The portion of the structure bid upon underlies parts of nine different tracts. Industry studies have indicated that in order for each leaseholder to evaluate his tract independently, 40% more exploratory wells will be required than if the structure were explored as a single unit (15). The obvious solution to this problem is to lease tracts configured to conform to the underlying structures. Unfortunately, for the larger and hence most important structures, this will result in lease tracts an order of magnitude larger than at present and roughly speaking an order of magnitude more valuable, greatly exacerbating our basic problem of very large bids in the face of very large uncertainties. One solution to this problem suggested by industry is pre-exploratory drilling unitization. That is, all successful bidders on tracts overlying a particular structure would get together, agree to explore and produce the structure as a unit, each operation receiving an agreed-upon percentage participation in the endeavor. Unfortunately, unitization hearings usually take years as operators bargain for the largest possible share. One balky operator can bring the negotiations to a standstill. As a result, complicated processes have developed to facilitate and force consummation of unitization agreements. In the past, these agreements have generally taken place only after the field has been delineated. The uncertainties prevailing prior to exploratory drilling will further complicate matters. In short, unless Draconian measures are instituted, the delays in exploration and development associated with pre-exploratory drilling unitization will be much larger than the delay associated with post-exploratory drilling bidding.

Under public exploratory drilling, each structure would automatically be explored as a unit and the economies associated with so doing would accrue as a matter of course. The savings obtained could easily outweigh the losses associated with the bidding delay and inability to use exploratory wells as producers.

A final argument sometimes offered for public exploratory drilling is environmental in nature. The idea being that the public need not commit itself to production until it has ascertained just what petroleum is there and presumably has a much more complete idea of the environmental risks that are there. The most often cited example is the Dos Cuadros field off Santa Barbara, where exploratory drilling revealed shallow deposits in a highly faulted, unstable reservoir. If public exploratory drilling were in effect, the nation would have had the option of simply walking away from the find if it so chose.

For my own part, I don't think the argument for public exploratory drilling on environmental grounds should be given too much weight. If one finds a significant amount of oil just about anywhere, there will be tremendous pressure to produce it regardless of the environmental hazards. However, it may well be possible to better tailor regulatory standards, such as casing and cementing requirements, to the particular characteristics of each find after exploratory drilling.

The final argument I am going to offer for public exploratory drilling will admittedly require a degree of wisdom and leadership on the part of the government, which there is no recent evidence of the country or its leaders being able to summon. As such, it must be regarded as a hypothetical argument. Nonetheless, it is certainly important enough to mention.

Several people have suggested that domestic offshore oil might be a weapon for putting downward pressure on OPEC (Organization of Petroleum Exporting Countries) crude prices. The foregoing discussion assumes that even extensive exploitation of domestic offshore petroleum would have little effect on the OPEC ceiling price. Under present and most proposed policies, I fear this will be the case. Given the difference between the cost of imported crude and the cost of offshore oil, each discovery would be developed quickly and its individual output swallowed up by the massive U.S. consumption without noticeable effect on the worldwide situation. Certainly the North Sea appears to have had little effect on OPEC prices.

However, if the United States and the other market nations were to follow a strong coherent policy of developing the importers' bargaining position, then offshore oil could be an important component of such a program. Such a policy would involve getting ourselves into a position where a buyers' boycott of a year or so is a credible threat. It would include importing more than our consumption and storing it, overdeveloping present fields and underproducing them, and exploring and extensively developing new fields, principally offshore, and not producing them. As the industry has pointed out, a policy like this would be extremely expensive. But it is still worth considering seriously. If, in the future, the threat of such a boycott were to keep the OPEC price one dollar per barrel less than it would otherwise be, it would be worth spending in excess of forty billion dollars now to achieve the capability of such a threat.

This is not the place to argue for such a policy. I only point out that if the United States were to follow a policy like this, then its handling of offshore oil would have to change drastically from present practice. Obviously, one cannot expect private capital to fund extensive exploration and overdevelopment of production facilities, and then shut in the entire mess just to use it as a bargaining chip to bring oil prices down. If we are to use offshore oil as a weapon against OPEC, we are going to have to, as with other weapons, keep it under public control. Public exploratory drilling would

1. maintain the option of using offshore oil as a bargaining weapon longer;
2. tend to sensitize the country to thinking of this oil as a public resource which might be used in this matter.

I can imagine, for example, if we moved publicly controlled rigs into all the top prospects in all frontier areas more or less simultaneously and if we found a lot of oil, that it might occur to the body politic that perhaps this oil should be consciously used to threaten OPEC with a boycott unless they lowered their prices, rather than drained as a matter of course. True, it would take a good deal of luck and a great deal more imagination than we have had in the recent past. But public exploratory drilling does hold out a slim thread of hope not offered by the other alternatives.

In summary, then, the public exploratory drilling question boils down to whether or not one feels that a publicly managed exploratory drilling program would be approximately as effective as an industry-managed program. If so, public exploratory drilling followed by bonus bidding is rather attractive from both national income and public income points of view.

CHAPTER 8

THE TIMING OF LEASE SALES

Whatever lease management program is finally selected, there will remain the problem of the scheduling of lease offerings. This scheduling problem raises an easily misunderstood, potential conflict between national income and public income. On the one extreme, the government could act like a profit-maximizing monopoly rationing out the leases at a rate which maximized the present value of government revenues from the sales. On the other extreme, the government could offer the entire OCS tomorrow.

Even assuming effective competition among bidders, the present value of government revenues will in general be less under sharply accelerated programs than under more gradual leasing. There are three possible reasons:

1. The additional production resulting from more rapid leasing could lower the landed price of petroleum, thereby decreasing the value of the tracts to the investor. As argued earlier, in order for this to happen, domestic production would have to expand to the point where all foreign oil would be forced off the market.

2. Non-price constraints on the petroleum industry's ability to expand to develop all the tracts offered would reduce the value of the tract to the bidder. These constraints include capital market imperfections, rig and platform construction delays, and lags in development of technical expertise.

3. Finally, it is obvious that all the problems in maintaining effective competition among bidders will be exacerbated when the limited number of bidders are spread out over a larger number of tracts.

It is important to distinguish between the possible causes listed. In the first case, the drop in public revenues will be matched by a drop in prices. Hence, the switch in the economic rent from governmental revenues to price decrease is a wash as far as public real income is concerned. In this case, the real income of the public _as a whole_ will not be affected. In the second case and in the case of less effective competition among bidders, the drop in present valued government revenues will be matched by an increase in developer profits.* In this case there will be a transfer of income from the public to the developer with sharply increased leasing.

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*Actually a portion of this increase will be transferred to various vendors (rig and platform builders, etc.) as lessees bid among themselves for the resources needed to explore and develop all the tracts available, which under expanded leasing will be in short supply for some time.

As we mentioned earlier, it is quite unlikely that domestic production can expand enough to force all imported crude off the market. Hence limitations on the rate at which the offshore industry can expand and problems in maintaining completion are the likely operative mechanisms in any large drop in present valued government revenues with increase in leasing rate. In this case, we have an interesting conflict between national and public income. If maximum national income is the objective (and assuming once again the OPEC price is regarded as immutable), the government should not hold back on any prospects <u>if by holding back it actually slows the development of OCS petroleum</u>. This is perhaps obvious. If there is oil whose resource cost is \$3.00 per barrel on the OCS when alternative oil is costing the nation \$11.00 and, as a result of restraints on leasing, this oil is not developed, then national income will be decreased by \$8.00. If due to leasing constraints, the development of this oil is delayed by five years, then national income will be decreased by the difference in present value.

$$\$8.00 - \left(\frac{8.00}{(1 + i)^5}\right)$$

Under the assumption that the real cost of capital to the nation is 10%, this difference is about \$3.00. If one expects the real cost on a constant dollar basis of alternative oil to rise at a rate of r%, then the unit change in national income with a delay of n years is approximately

$$\$8.00 - \frac{8.00(1 + r)^n}{(1 + i)^n}$$

As long as the real increase in oil price is less than the cost of capital, there will be a loss in national income associated with a leasing imposed delay.

As a practical matter, the conflict between national income and public income inherent in the lease scheduling decision need not be an insurmountable hurdle. As mentioned earlier, the capital market problems primarily involve the high risks associated with present pre-exploratory drilling bonus bidding. Under either excess profits bidding or public exploratory drilling, the bulk of the capital market constraints will disappear. Platform and rig construction lags are a two or three-year proposition. Rig and platform yards are rather simple propositions and can expand almost as rapidly as one can build a rig.

Under whatever bidding scheme is in question, the obvious compromise is an accelerated leasing program geared to a guess at the maximum rate at which the offshore industry can expand. Such a leasing rate will necessarily involve some transfer of economic rent to the developer. This will be necessary to divert the additional resources to offshore petroleum rapidly. But very little beyond a rate of return slightly in excess of the normal system plus some degree of assurance that the leases will continue to be scheduled fairly rapidly will be required to bring on the rigs as fast as they can be brought on. Capital market problems and problems in maintaining effective competition aside, the compromise from the point of view of the shift in economic rent to the developer need not be a massive one. And if a shift to net profit bidding or public exploratory drilling occurs, both the capital market problems and problems in maintaining effective competition will be greatly ameliorated.

In summary, then, from the point of view of national income, as long as one believes the real cost of capital will be greater than the real rate of inflation in foreign crude prices, there is an extremely strong argument for greatly expanded leasing. Under the present system such an expanded program would undoubtedly result in a transfer of income from the public to the developer. However, under either excess profits bidding or public exploratory drilling, this transfer need not be large, especially if the rate of expansion in the early years of the program is geared to the ability of the offshore rig and offshore drilling industries to expand. Under the present system, the sharp expansion in leasing indicated by maximum national income considerations could easily involve a substantial transfer of the economic rent to the developer and his suppliers, due primarily to capital market imperfections and the limited number of bidders. Hence, the argument for greatly expanded leasing on national income grounds is also an argument for a switch to excess profits bidding or public exploratory drilling on public income grounds.

A corollary to this is that, if a public exploratory drilling program is decided upon, from a national income point of view it should be funded at the same rate that the market would fund exploratory drilling under the accelerated leasing program. This may require some excess profits for the government contractors under the exploratory program until the industry expands to handle the real national income maximizing rate. One of the dangers associated with public exploratory drilling is that it would be underfunded, in which case in order to stay within the budget, individual prospects won't be explored with national income maximizing thoroughness, i.e. they will be written off early. One check against this might be a rule requiring the government to offer for lease every prospect when the government exploratory program is completed, however unsuccessful. If prospects which the government had written off drew substantial bids or later showed a pattern of successful development, then it would be a sure sign that the public exploratory drilling program is not thorough enough from the point of view of public income. In any case, there would be no loss in national income.

CHAPTER 9

WELL AND RESERVOIR PRODUCTION RATE REGULATION

Assuming one is not attempting to use offshore oil as a bargaining chip against OPEC and assuming one believes the market is as good an estimator of the future oil prices as any, there is simply no argument for well rate regulation (MPR's) or reservoir production rate regulation (MER's) from either a national income point of view, a public income point of view, or a developer income point of view. As mentioned earlier, as long as one believes the developer's cost of capital is approximately equal to the nation's, the developer(s) will produce each unitized reservoir at the rate which will maximize their present values and as long as one has not imposed a tax and royalty system whose form is such that the developers' effective marginal price is different from the cost to the nation of imported crude, then maximization of developers' present value will maximize national income. Common pools can be dealt with directly and naturally by unitization requirements. MPR's and MER's should be scrapped forthwith.

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